BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF HAWAII

In the Matter of the Application of)
)
MAUI ELECTRIC COMPANY, LIMITED) Docket No. 2006-0387
)
For Approval of Rate Increases and)
Revised Rate Schedule and Rules)
)

MECO
2007 TEST YEAR

DIRECT TESTIMONIES AND EXHIBITS

Book 4 of 5

February 23, 2007

MECO T-13
DOCKET NO. 2006-0387

TESTIMONY OF
LON K. OKADA

MANAGER
CORPORATE TAXES
HAWAIIAN ELECTRIC INDUSTRIES, INC.

Subject: Taxes Other Than Income Taxes
Income Tax Expense
Unamortized Net SFAS 109 Regulatory Asset
Unamortized Investment Tax Credits
Accumulated Deferred Income Taxes
Recent Tax Developments

INTRODUCTION

Q. Please state your name and business address.

A. My name is Lon K. Okada and my business address is 900 Richards Street, Honolulu, Hawaii.

Q. By whom are you employed and in what capacity?

A. I am employed by Hawaiian Electric Industries, Inc. ("HEI") and my title is Manager of Corporate Taxes. MECO-1300 provides my educational background and work experience.

Q. What are your areas of responsibility in this proceeding?

A. My testimony will cover the following areas for the 2007 test year for Maui Electric Company, Ltd. ("MECO" or "Company"):

1) Taxes Other Than Income Taxes,
2) Income Tax Expense,
3) Unamortized Net SFAS 109 Regulatory Asset
4) Unamortized Investment Tax Credits,
5) Accumulated Deferred Income Taxes, and
6) Recent Tax Developments.

To the extent possible, the amounts for each island division are stated separately for use in determining each island's revenue requirements. Thus, each area of testimony will include the individual 2007 test year numbers for the Maui, Lanai and Molokai divisions, as well as the total MECO amounts.

Q. Please explain the terms "under present rates" and "under proposed rates" as used in this testimony.

A. Some of the test year estimates covered in this testimony, such as Taxes Other than Income Taxes, are affected by the rates charged by MECO to ratepayers.

For these estimates, test year amounts are provided based on the rates currently approved by the Commission ("present rates") and based on rates proposed by the Company in this docket ("proposed rates").

TAXES OTHER THAN INCOME TAXES

Q. What are the specific taxes included in "Taxes Other than Income Taxes"?

A. The following six taxes are included in this category and are related either to payroll or to utility revenue:

1) The Federal Insurance Contribution Act and Medicare ("FICA/Medicare") taxes,
2) The Federal Unemployment ("FUTA") tax,
3) The State Unemployment ("SUTA") tax,
4) The State Public Service Company ("PSC") tax,
5) The State Public Utility ("PUC") fee, and
6) The County Franchise Royalty tax.

Q. What are MECO's test year estimates for Taxes Other than Income Taxes?

A. The estimated amounts included in MECO's 2007 test year operating expenses as "Taxes Other than Income Taxes" are shown in MECO-1301. Under present rates, the 2007 test year estimates for Taxes Other Than Income Taxes are $30,918,000 for Maui, $952,000 for Lanai, $1,198,000 for Molokai and $33,068,000 for total MECO. Under proposed rates, the 2007 test year estimates for Taxes Other Than Income Taxes are $ 32,490,000 for Maui, $1,000,000 for Lanai, $1,258,000 for Molokai and $ 34,748,000 for total MECO.

1) FICA/Medicare Tax

Q. What is the 2007 test year FICA/Medicare tax expense?

A. The Company's estimated 2007 test year FICA/Medicare tax expense is $1,196,000 for Maui, $53,000 for Lanai, $66,000 for Molokai and $1,315,000 for total MECO.

Q. How are these amounts determined?

A. The test year FICA/Medicare tax expense includes two elements, the FICA portion and the Medicare portion. Both are based on taxable wages, but the FICA wage base is limited by a maximum amount per employee while the Medicare wage base is unlimited.

For the 2007 test year, the FICA portion of the tax has a per employee maximum taxable wage base of $97,500 at a rate of 6.2%. The Medicare portion of the tax for 2007 is based on a rate of 1.45% with no wage base limitation. The test year estimate of FICA/Medicare taxes was obtained by applying the effective tax rates actually experienced in 2005 to the 2007 test year estimates of gross pay by pay period. The effective tax rates are calculated for each quarter and represent the ratio of FICA/Medicare taxes paid to total compensation earned during the quarter, as reported for payroll tax purposes. The effective tax rate trends downward as the year progresses, as more employees reach the FICA maximum wage base. See MECO-WP-1301, page 3 for the calculation of the FICA/Medicare taxes.

Q. How is the total FICA/Medicare tax allocated to operations, capital projects and billable projects?

A. The total FICA/Medicare tax is calculated and then allocated amongst operations, capital projects and billable projects based on the estimated division of labor charges to these three categories. See MECO-WP-1301, page 2. The amount allocated to operating expenses is included in Taxes Other than Income Taxes.

The amount allocated to capital projects represents charges to construction work in progress that eventually are closed to plant in service. The cost of these payroll taxes is recovered through the depreciation of plant in service. The amount allocated to billable projects is assumed to be recovered through outside billings to third parties with no net cost or benefit to the Company.

Q. Why is this allocation methodology reasonable?

A. As previously explained, total FICA/Medicare tax is equal to the applicable tax rate times test year wages. These wages are essentially equivalent to total labor charges. Therefore, allocating FICA/Medicare tax charges according to where labor is charged is a reasonable method of allocation. This methodology was approved and used by the Commission in MECO's last general rate case (Amended Decision and Order No.16922 ("D&O 16922") in Docket No. 97-0346, MECO's test year 1999 rate case).

2) FUTA Tax

Q. What is the 2007 test year FUTA tax expense?

A. The Company's FUTA tax expense estimate for the 2007 test year is $12,000 for Maui, $1,000 for Lanai, $1,000 for Molokai and $14,000 for total MECO, as shown in MECO-1301.

Q. How are these amounts determined?

A. FUTA taxes are based on a taxable wage base of $7,000 per employee and a net tax rate of 0.8% in accordance with Internal Revenue Code ("IRC") §3301 and §3302. The allocation of this tax cost between operations, capital, and billable projects is identical to the methodology used for the FICA/Medicare tax explained earlier in this testimony. This methodology was accepted by the Commission in its D&O No. 16922 in Docket No. 97-0346 in determining MECO's revenue requirements.

3) SUTA Tax

Q. What is the 2007 test year SUTA tax expense?

A. The Company's SUTA tax expense estimate for the 2007 test year is $45,000 for Maui, $2,000 for Lanai, $2,000 for Molokai and $49,000 for total MECO, as shown in MECO-1301. The Company's test year estimate is based on a rate of 0.61% and a wage base of $35,700. The rate and taxable base are set annually by the State of Hawaii Department of Labor and Industrial Relations, and the applicable rate is determined by a rate schedule based on a ratio, which measures a company's funded status relative to its latest three year average taxable payroll.

Q. How did the Company estimate the 2007 test year rate and base?

A. The Company estimated that the 2007 test year rate would be identical to the 2006 approved rate of 0.61%. The test year base of $35,700 was estimated by starting with the State-approved 2006 base of $34,000 and adding $1,700, which is the same increase in base experienced between 2005 and 2006. This increase is reasonable in light of the State's recent history of progressively larger increases year over year. In the last eight years, there was only one instance where the SUTA taxable base decreased. The State is expected to notify MECO of its 2007 rate and base before the end of the first quarter of 2007.

4) PSC Tax

Q. What is the 2007 test year PSC tax expense?

A. Under present rates, the PSC tax expense for the 2007 test year is estimated at $19,672,000 for Maui, $594,000 for Lanai, $749,000 for Molokai and $21,015,000 for total MECO. Under proposed rates, the PSC tax expense for the

2007 test year is estimated at $20,716,000 for Maui, $626,000 for Lanai, $789,000 for Molokai and $22,131,000 for total MECO, as shown in MECO-1301.

Q. How is the PSC tax determined?

A. The tax is imposed on the gross utility revenues of the Company at a base rate of 5.885% in accordance with Hawaii Revised Statutes ("HRS") §239-5. The tax rate increases by an incremental percentage if the ratio of PSC net income to PSC gross taxable revenue is in excess of 15%. However, in recent years, the Company's ratio has been below the 15% threshold. The test year's ratio will also be less than 15% based on the projected PSC net income to PSC gross taxable revenue ratio. Accordingly, the Company has applied the 5.885% minimum rate in calculating its test year PSC tax expense. HRS §239-5 also provides that the tax in excess of the tax at 4% will be paid to the County in which the Company generates its taxable revenue. In this case, the excess calculated at the rate of 1.885% will be the portion owed to the County of Maui. MECO has used the 5.885% rate to calculate test year PSC tax expense in its most recent rate cases.

5) PUC Fee

Q. What is the 2007 test year PUC fee expense?

A. Under present rates, the 2007 test year PUC fee expense is estimated at $1,671,000 for Maui, $50,000 for Lanai, $64,000 for Molokai and $1,785,000 for total MECO. Under proposed rates, the 2007 test year PUC fee expense is estimated at $1,760,000 for Maui, $53,000 for Lanai, $67,000 for Molokai and $1,880,000 for total MECO. This is shown in MECO-1301.

Q. How is the PUC fee determined?

A. The fee is determined by multiplying gross utility revenues by a statutory semiannual rate of .25%, or .5% annually, as set forth in HRS §269-30(b).

6) Franchise Royalty Tax

Q. What is the 2007 test year Franchise Royalty tax expense?

A. Under present rates, the 2007 test year Franchise Royalty tax expense is estimated at $8,322,000 for Maui, $252,000 for Lanai, $316,000 for Molokai and $8,890,000 for total MECO. Under proposed rates, the 2007 test year Franchise Royalty tax expense is estimated at $8,761,000 for Maui, $265,000 for Lanai, $333,000 for Molokai and $9,359,000 for total MECO. This is shown in MECO-1301.

Q. How is the Franchise Royalty tax determined?

A. The Franchise Royalty tax is computed by multiplying gross receipts from the sale of electricity by a rate of 2.5% in accordance with MECO's franchise and HRS §240-1.

INCOME TAX EXPENSE

Q. What is the 2007 test year income tax expense?

A. Under present rates, the 2007 test year income tax expense is estimated at $9,122,000 for Maui, $(175,000) for Lanai, $124,000 for Molokai and $9,071,000 for total MECO. See MECO-1302, page 1. Under proposed rates, the 2007 test year income tax expense is estimated at $15,415,000 for Maui, $16,000 for Lanai, $366,000 for Molokai and $15,797,000 for total MECO. See MECO-1302. The calculations of income taxes at present and at proposed rates both utilize a top composite rate of 38.9097744%. This rate assumes the top marginal federal income tax rate of 35% and a state income tax rate of 6.4%. This combined rate became effective as of January 1, 1993 after the Revenue Reconciliation Act of 1993. The calculations are shown on MECO-WP-1302, page 1.

Q. What method did MECO use to compute the test year income tax expense?

A. MECO calculated the test year income tax expense based on the "short form" method that the Commission has consistently adopted in previous rate cases, including MECO's last general rate case D&O No. 16922 (April 6, 1999) in Docket 97-0346.

"Short Form" Income Tax Methodology

Q. What is the "short form" method of calculating income tax expense?

A. The "short form" method is used for ratemaking purposes and calculates the total income tax expense in one step, rather than calculating the current and deferred components of income tax expense separately.

Q. Why is the "short form" method used?

A. This method simplifies the calculation of income tax expense and was used as the income tax calculation methodology for ratemaking purposes in recent rate case decisions for MECO, HECO and HELCO.

Q. How does the "short form" method simplify the calculation of income tax expense?

A. The "short form" method simplifies the calculation of income tax expense by utilizing net operating income before income taxes, with certain adjustments which are explained below. This adjusted net operating income is the taxable income for ratemaking purposes.

Taxable income for ratemaking purposes is multiplied by the composite federal/state income tax rate of 38.9097744%. The resulting amount is the income tax expense utilized in deriving net operating income for ratemaking purposes.

Adjustments to Derive Taxable Income for Ratemaking Purposes

Q. Please explain the derivation of taxable income for ratemaking purposes, starting with the calculation of net operating income before income taxes.

A. Net operating income before income taxes is equal to operating revenues less operation and maintenance expenses, depreciation expense, amortization of state capital goods credit ("state ITC"), taxes other than income taxes and interest expense on customer deposits.

Q. What types of adjustments are made to net operating income before income taxes to derive test year taxable income for ratemaking purposes?

A. There are two categories of adjustments:

1) Interest expense related to operations, and
2) Permanent book/tax differences.

<u>Interest Expense Related to Operations</u>

Q. Why does interest expense related to operations reduce taxable income for the calculation of income taxes?

A. For ratemaking purposes, interest expense related to operations is recovered in rates as a component of the allowed rate of return on rate base (specifically, the debt rate embedded in the weighted cost of capital) which is expressed on a pretax basis. The interest component, however, is tax deductible and must therefore be included in the calculation of income tax expense in order to account for the tax benefit related to the deductible interest.

Q. What is the 2007 test year interest expense estimate?

A. The 2007 test year estimated interest expense is $9,078,000 for Maui, $377,000 for Lanai, $440,000 for Molokai and $9,895,000 for total MECO, as shown in MECO-1302.

Q. How is this interest expense calculated?

A. The 2007 test year interest expense for total MECO of $9,895,000 is calculated based on the same methodology used by MECO in Docket No. 97-0346 and used by the Commission in determining MECO's revenue requirements in that docket.

This method estimates the amount of interest expense by calculating the interest on the long-term debt and hybrid securities actually in place and on the estimated additional long-term debt and short-term debt to be required in the test year. This total interest is then reduced by the debt portion of the Allowance for Funds used during Construction ("AFUDC") for the year (see discussion below) as shown in MECO-WP-1302, page 2.

Q. Why is interest expense reduced by the debt portion of AFUDC?

A. AFUDC is the calculated cost of funds used for the construction of utility assets and is capitalized to plant in service. AFUDC is comprised of a debt and equity portion, and in accordance with Statement of Financial Accounting Standards ("SFAS") No. 109, the Company computes AFUDC on a pretax basis. The debt portion of AFUDC represents the portion of total interest costs related to construction of assets. The debt component adjustment carves out the interest expense related to construction, leaving the interest expense related to operations. The tax benefit of the interest deduction related to operations is appropriately flowed through the test year.

Q. Why is it necessary to exclude the tax benefit related to the debt portion of AFUDC in computing the income tax expense for the test year?

A. The pretax debt portion of AFUDC represents the amount of estimated interest expense related to the construction of capital assets and is capitalized to plant. This AFUDC is capitalized as part of the construction cost of those capital assets. The Company recovers these capitalized costs, including AFUDC, through depreciation expense and accordingly, flows the related tax benefits through to the customers in future years when depreciation is taken. Thus, the debt portion of AFUDC must be excluded from the interest deducted in the calculation of income tax expense to avoid double counting these income tax benefits.

Permanent Book/Tax Differences

Q. What are "permanent book/tax differences"?

A. Permanent book/tax differences are items that are recognized in the calculation of regulatory and book net income that will never be recognized in taxable income or vice versa.

Q. What is the total amount of the "permanent book/tax differences" estimated for the 2007 test year?

A. For the 2007 test year, the only permanent book/tax difference is for meals and entertainment expenses in the estimated amounts of $29,000 for Maui, $1,000 for Lanai, $1,000 for Molokai and $31,000 for total MECO, as shown in MECO-1302.

Q. Why are meals and entertainment expenses treated as a permanent book/tax difference?

A. Meals and entertainment expenses are reasonable costs of doing business. However, only 50% of these expenses are deductible for tax purposes and recognized in the calculation of taxable income. Therefore, 50% of these expenses are added back in determining taxable income for ratemaking purposes. This treatment is consistent with the determination of income taxes in prior rate cases, including Docket No. 97-0346. See MECO WP-1302, page 4, for the calculation of the estimated test year meals and entertainment add back.

Accounting for the State Capital Goods Excise Tax Credit

Q. What is the 2007 test year amortization of the state capital goods excise tax credit?

A. The 2007 test year estimated amortization of the state capital goods excise tax credit ("state ITC") is $475,000 for Maui, $20,000 for Lanai, $23,000 for Molokai and $518,000 for total MECO. See MECO-1304.

Q. What is the state ITC?

A. The state ITC was enacted in 1987 under HRS §235-110.7 and was designed to mirror the qualification rules of the old federal investment tax credit ("ITC"). The four percent credit applies to qualifying equipment purchased and placed into service by businesses in Hawaii.

For book and ratemaking purposes, the credit is deferred in the year earned and is subsequently amortized over the estimated useful life of the associated asset as was done with the federal ITC. The amortization of state ITC on new additions begins when the book depreciation commences on those additions.

Q. How does the 2007 test year presentation of the amortization of the state ITC differ from past rate case presentations?

A. In past rate cases, the net amortization of the state ITC was included as an adjustment to income tax expense. It was shown net of federal and state tax effects because state ITC is effectively taxable for federal and state income tax purposes.

The current 2007 test year presentation yields the same net income result but is presented gross of taxes as a pretax amortization of the state ITC in operating income for ratemaking purposes. The federal and state income tax expense related to the state ITC is calculated and included in income tax expense. The current presentation is more consistent with the financial presentation under SFAS 109, which favors a "gross of tax" presentation.

Accounting for Federal Investment Tax Credit

Q. What is the 2007 test year amortization of federal ITC?

A. The estimated 2007 test year amortization of federal ITC is $212,000 for Maui, $2,000 for Lanai, $-0- for Molokai and $214,000 for total MECO. See MECO-1303. For ratemaking purposes, the credits earned and taken in prior years' income tax returns are amortized over 30 years, which is the approximate composite useful life of the assets giving rise to the credits. The amortization of federal ITC (formerly included as an adjustment to income tax expense prior to SFAS 109) is now included as an adjustment in determining depreciation expense. See MECO-1201.

Q. What is the 2007 test year amortization of the regulatory liability related to federal ITC?

A. The estimated 2007 test year amortization of the regulatory liability related to federal ITC is $122,000 for Maui, $6,000 for Lanai, $8,000 for Molokai and $136,000 for total MECO. See MECO-1306.

Q. What is the relationship between federal ITC and this regulatory liability?

A, As mandated by SFAS 109, Accounting for Income Taxes, the regulatory liability represents the "gross-up" for the tax effect of the ITC amortization and the tax on tax. See MECO-WP-1306. The amortization of the regulatory liability (credit to depreciation expense) has no impact on revenue requirements or net income because this amortization is offset by a corresponding increase (debit) to deferred income tax expense. The regulatory liability is amortized over the same period as the related federal ITC.

Q. How is the amortization of federal ITC treated?

A. Under SFAS 109, the amortization of federal ITC is considered a temporary difference on which a deferred tax must be provided. A regulatory liability is established as the equal and offsetting credit to the deferred income tax asset. This is an artificial creation of SFAS 109 since federal ITC never entered into the computation of taxable income for federal income tax return purposes. Federal ITC was a credit (as opposed to a deduction) that reduced the calculated income tax liability, dollar for dollar.

Consequently, the amortization of this regulatory liability increases net operating income by the identical amount of income tax expense calculated on the combined amortization of federal ITC and the related regulatory liability. The amortization of the regulatory liability and the additional income tax expense are equal and offsetting, resulting in the same revenue requirements impact of federal ITC before SFAS 109. In the 2007 test year, the debit to the regulatory liability of $136,000 for total MECO offsets the credit to the Federal ITC deferred tax asset of $136,000. These amounts can be verified by taking the change in the year-end balances of the regulatory liability and the Federal ITC deferred tax asset. See MECO-1307.

<u>UNAMORTIZED NET SFAS 109 REGULATORY ASSET</u>

Q. What is the 2007 test year average net unamortized SFAS 109 regulatory asset?

A. The estimated 2007 test year average unamortized net SFAS 109 regulatory asset is $7,972,000 for Maui, $429,000 for Lanai, $518,000 for Molokai and $8,919,000 for total MECO, as shown in MECO-1306. This represents the "gross up" of taxes required under SFAS 109. The equal and offsetting accumulated deferred income tax liabilities were provided as illustrated in MECO-1307.

Q. How was the 2007 test year average net unamortized SFAS 109 regulatory asset calculated?

A. The Company calculated this amount by taking the average of the SFAS 109 regulatory asset at the beginning and end of the test year. The balance at the beginning of the test year is the estimated net SFAS 109 regulatory asset as of December 31, 2006. The balance at the end of the test year was derived by utilizing the estimated net SFAS 109 regulatory asset as of December 31, 2006, reducing it by the 2007 test year estimate of the amortization of the net regulatory asset and adding the 2007 test year estimate of the gross up of AFUDC equity incurred.

Excess Deferred Income Taxes

Q. How does the Company's adoption of SFAS 109 alter the presentation of excess deferred income taxes?

A. SFAS 109 requires that deferred tax liabilities and assets be established to reflect changes in income tax rates. Consequently, the income tax rate reduction enacted by the 1986 Tax Reform Act ("TRA") required an adjustment to the Company's deferred income tax balance as of January 1, 1993. Consistent with SFAS 109's focus on the balance sheet, the portion of the deferred tax balance (established prior to 1987 at higher rates) in excess of that which is required to satisfy future tax liabilities at the 1986 TRA 34% rate represents excess deferred taxes. This excess was carved out and classified as a regulatory liability.

In addition, the amount carved out as a regulatory liability was grossed up to reflect the fact that the amortization of this regulatory liability represents current and future revenue reductions which have a related tax effect. Mechanically, this is accomplished by computing the tax effect of the regulatory liability plus the tax on the computed tax. The "gross up" amount serves to increase the regulatory liability with an equal and offsetting debit to accumulated deferred income tax liability.

Q. How does the SFAS 109 book treatment affect the ratemaking presentation of excess deferred income taxes?

A. Because the future financial statement impact of the excess deferred taxes is now reflected in the resulting regulatory liability, the reduction of test year income tax expense is now accomplished in two pieces: 1) through the amortization of the "grossed up" regulatory liability included in operating income and 2) the income taxes calculated on the amortization. For ratemaking purposes, the net operating income impact is equivalent to the former adjustment to income tax expense for excess deferred taxes in the calculation of income tax expense.

Q. What is the 2007 test year amortization of the regulatory liability related to excess deferred income taxes?

A. The estimated 2007 test year amortization of the regulatory liability related to excess deferred taxes is $3,000 for Maui, $-0- for Lanai, $-0- for Molokai and $3,000 for total MECO. See MECO-1306, page 2. This amount was calculated by determining that amount of excess deferred income tax benefit flowing back to ratepayers. This is consistent with the treatment of excess deferred taxes in Docket No. 97-0346.

Q. Please describe the background of excess deferred income taxes and the methodology used in determining the benefit flow back.

A. The TRA of 1986 contained a provision which reduced the top corporate income tax rate from 46% to 40% in 1987 and to 34% in 1988 and subsequent years. In years prior to 1987, deferred income taxes were calculated and established at the then current 46% rate under the assumption that the taxes would be paid at the higher 46% rate in the future when the underlying timing differences "turned around."

The change to these lower rates created the excess deferred taxes, and the law required that regulated utilities normalize those excess deferred income taxes related to accelerated depreciation.

Under SFAS 109, the amortization of the regulatory liability accomplishes what was previously accomplished via the amortization of excess deferred taxes, and accordingly, the methodology for the amortization of this regulatory liability parallels the methodology previously used for excess deferred taxes.

Q. How was the amortization of the regulatory liability related to excess deferred income taxes calculated?

A. The amortization of the regulatory liability related to the excess deferred income taxes can be divided into two categories. The first category deals with excess deferred taxes related to accelerated depreciation in account 282. The second category includes excess deferred taxes in account 283, which are for all items other than accelerated depreciation.

Under the 1986 TRA, regulated utilities must use the average rate assumption method in calculating the flow back of excess deferred taxes related to accelerated depreciation for all vintages subject to the normalization rules of the tax code. Under the average rate assumption method, the flow back of tax benefits is normalized over the book life of the associated assets. SFAS 109 does not change the tax normalization requirement contained in the TRA of 1986. Therefore, the average rate assumption method was used for all vintages after 1970. Excess deferred taxes related to accelerated depreciation on pre-1971 vintages were not subject to the average rate assumption method. As of 12/31/06, the Company's regulated liability related to excess deferred taxes on accelerated depreciation was fully amortized.

Q. How does the Company calculate the amortization of the regulatory liability related to all excess deferred income taxes other than those related to accelerated depreciation?

A. The regulatory liability related to all excess deferred taxes other than those related to accelerated depreciation is being amortized over the estimated remaining life of the underlying timing differences. This amortization method was used in MECO's previous rate cases including Docket No. 97-0346. The amortization of the regulatory liability, under SFAS 109, has the same effect and result on revenue requirements as the amortization of excess deferred income taxes under the superseded APB 11 methodology. In MECO's case, the regulatory asset/liability was an asset (debit) balance since the excess deferred taxes related to negative deferred items. This balance is estimated to be fully amortized at the end of the 2007 test year.

Q. Why are the revenue requirements the same under the old and new accounting rules?

A. Under the old APB 11 rules, excess deferred income taxes were treated as a direct adjustment to income tax expense, and the amortization of excess deferred income taxes reduced income tax expense dollar for dollar.

Under SFAS 109, the grossed up excess deferred income taxes are amortized into operating income, and income taxes are calculated on that amortization. The impact on operating income is exactly the same as under

APB 11 since the grossed up number net of its tax effect is equal to the excess deferred tax amortization before gross up.

Q. How does the Company's adoption of SFAS 109 impact rate base?

A. SFAS 109 has no impact on rate base. Although SFAS 109 requires MECO to establish certain tax-related regulatory assets and liabilities, equal and offsetting entries are made to accumulated deferred income taxes.

Q. With respect to state taxes, how does the Company handle the amortization of excess state deferred income taxes?

A. MECO amortizes state excess deferred income taxes in the same manner as it amortizes federal excess deferred taxes.

Deficit Deferred Income Taxes

Q. How does the 1993 Omnibus Budget Reconciliation Act ("1993 Tax Act") affect the deferred income tax balances for the 2007 test year?

A. The 1993 Tax Act increased the income tax rate by one percent, from 34% to 35%. As a result, the federal deferred income tax liability balances were deficient by that one percent since the underlying temporary differences are expected to reverse at the current 35% rate.

Q. What does SFAS 109 require in this instance where the income tax rate increases?

A. Under SFAS 109's balance sheet orientation, MECO must provide the additional deferred income taxes to cover this one percent deficit since the deferred tax liability balances were adjusted at the beginning of 1993 to provide for future taxes at the lower 34% rate.

Q. What accounting adjustments were made upon the enactment of the higher 1993 income tax rate?

A. Consistent with the treatment of excess deferred income taxes, the one percent deficit deferred tax was calculated and grossed up for the tax on tax effect. This amount was then set up as an additional deferred income tax liability with an offsetting regulatory asset. In effect, this adjustment reinstates a portion of the excess deferred income taxes previously carved out and placed into the regulatory liability account.

Q. What is the 2007 test year amortization of the regulatory asset related to deficit deferred income taxes?

A. The estimated 2007 test year amortization of the regulatory asset related to deficit deferred income taxes is $28,000 for Maui, $2,000 for Lanai, $2,000 for Molokai and $32,000 for total MECO. See MECO-1306. These amounts were calculated using a method similar to how excess deferred taxes were computed, as explained earlier.

Q. Why is the amortization of the regulatory asset related to deficit deferred taxes included in the depreciation expense calculation?

A. The amortization of this regulatory asset related to deficit deferred taxes is the converse of the amortization of the regulatory liability related to excess deferred taxes. Whereas excess deferred taxes resulted from the tax rate decrease contained in the TRA of 1986, deficit deferred taxes are caused by the tax rate increase contained in the 1993 Tax Act. This amortization has the effect of increasing cost of service for deferred taxes, which were established at a 34% rate upon the adoption of SFAS 109 at the beginning of 1993, in order to meet the expected future liability at the higher current rate of 35%.

UNAMORTIZED INVESTMENT TAX CREDITS

Q. What is the 2007 test year estimate of the average unamortized federal and state investment tax credits?

A. The 2007 test year estimate of the average unamortized investment tax credits is $10,279,000 for Maui, $428,000 for Lanai, $499,000 for Molokai and $11,206,000 (rounded) for total MECO. See MECO-1304. The entire balance is made up of the state ITC. The federal ITC originating in years prior to 1971 was fully amortized as of December 31, 1999.

Q. How was the 2007 test year average unamortized investment tax credit calculated?

A. The Company calculated this amount by taking the average of the state ITC at the beginning and end of the test year. The balance at the beginning of the test year was derived by utilizing the recorded unamortized state ITC as of December 31, 2005, subtracting the 2006 estimated amortization of state ITC and adding the estimated state ITC earned in 2006. The balance at the end of the test year was similarly derived by utilizing the comparable 2007 test year estimates of state ITC amortization and 2007 vintage state ITC additions. See MECO-1304.

Q. What is the Company's position regarding the regulatory treatment of benefits due to the state ITC?

A. Because there are no laws or regulations that require the sharing of the state ITC benefits between ratepayers and shareholders, the Company passes all of the benefits of the state ITC to the ratepayers. Thus, the unamortized balance serves to reduce rate base and the annual amortization reduces income tax expense. This treatment of the state ITC benefit was used by the Commission in determining MECO's revenue requirement in prior rate cases, including Docket No. 97-0346.

ACCUMULATED DEFERRED INCOME TAXES

Q. What is the 2007 test year estimate of the average accumulated deferred income taxes ("ADIT")?

A. The average ADIT estimate for 2007 is $18,823,000 for Maui, $782,000 for Lanai, $913,000 for Molokai and $20,518,000 for total MECO, as shown in MECO-1305.

Q. How does the ADIT balance affect rate base?

A. MECO's net positive ADIT balance (which is a credit to a liability account) reduces rate base.

Q. How did the Company calculate the average ADIT balance?

A. The Company calculated this amount by taking the average of the estimated accumulated federal and state deferred tax balances at the beginning and end of the test year. The balance at the beginning of the test year was derived by utilizing the September 30, 2006 recorded deferred federal and state income tax balances and adding the estimated deferred income tax expense for the last three months of the year ending December 31, 2006. The balance at the end of the test year was derived by utilizing the estimated deferred federal and state income tax balances as of December 31, 2006 and adding the estimated deferred income tax expense for the 2007 test year. Consistent with prior MECO rate cases, the deferred taxes for items excluded in determining MECO's revenue requirements in prior rate case decisions have been excluded from the deferred tax balance for the test year. See MECO-WP-1305.

Q. Why are there reconciling amounts from the 2007 test year average ADIT balances used in revenue requirements to the corrected average ADIT balances shown on MECO-1305?

A. The differences were due to corrections to the balances of deferred income tax items that are excludable from rate base. These adjustments will be corrected at the next opportunity.

Status of Application to the IRS for Change in Accounting Method

Q. What is the status of the application to the Internal Revenue Service for a change in accounting method related to the overhead costs allocated to self-constructed assets—i.e., the simplified service cost method?

A. On February 9, 2007, the Company received a letter from the Internal Revenue Service (IRS) granting permission to change its method of accounting to the simplified service cost method, subject to the guidance in Revenue Ruling 2005-53 and any other administrative guidance or directives subsequently issued by the IRS. The background of this change was fully explained in my testimony for Hawaiian Electric Company, Inc. ("HECO") in its rate case Docket No. 04-0113 (see T-17, page 22 and RT-17, pages 11-14). At that time, the Company had a pending application with the IRS for accounting method changes related to the overhead costs allocated to self-constructed assets.

Q. How does the receipt of this consent to change affect MECO?

A. The consent has no impact on the 2007 test year. The IRS has granted permission for MECO to change its accounting method of allocating overhead costs, and this would prompt the filing of amended returns for 2001. However the permission was subject to the guidance in Revenue Ruling 2005-53, and any amended return filed under the new method will be subject to examination by the IRS. As described below, this ruling defined qualifying self-constructed assets to be only short-lived assets. Substantially all MECO's assets are long-lived assets and would not qualify for the new method. Consequently, without further guidance, the IRS consent to change should have no impact on the 2007 test year. The IRS is expected to issue further guidance, but the timing of issuance and the form of this future guidance is yet unclear.

Background of the Simplified Service Cost Application

Q. Please summarize the background of this application with the IRS.

A. In early 2002, MECO (with the assistance of Deloitte and Touche LLP) submitted an application to the IRS requesting a change in the method of allocating certain overhead costs, which the IRS refers to as "mixed service costs," for income tax purposes. This "simplified service cost" method affects the timing of the deduction for mixed service costs incurred in constructing certain "self-constructed" assets. The Company requested this change to be effective for the years ending on or after December 31, 2001.

Q. What was the effect of the requested method change on the Company's federal and state income tax returns?

A. To date, the requested method change has not resulted in any additional deductions and related tax benefits to the Company in its filed returns. MECO filed a "manual" application for change, which contemplated 1) the request for the change, 2) an approval from the IRS and 3) the deduction being taken only after approval was granted. If approval was received after the original due date of the 2001 return, then the deduction would be taken on an amended return.

Q. What guidance has the IRS issued on the simplified service cost method?

A. Although the Company has not received any direct guidance, on August 29, 2005, the IRS issued Revenue Ruling 2005-53 ("Revenue Ruling"), which summarized the guidance in the form of regulations (T.D. 9217), issued on August 2, 2005, relating to the uniform capitalization rules of IRC Sec. 263A and the simplified service cost method.

Q. Please explain the IRS's position in the regulations issued.

A. The IRS confirmed that taxpayers are allowed to use the simplified service cost method to determine the aggregate portion of mixed service costs (overheads) incurred that are allocable to "eligible property." The IRS then clarified what types of property constituted "eligible property" for purposes of these rules.

Q. How does the IRS define eligible property in the revenue ruling and the new regulations?

A. As it relates to electric utilities, the IRS defines eligible property narrowly and basically carves out all generation, transmission and distribution property from the allocation base due to their long useful lives. In its ruling, the IRS states, "For purposes of the simplified methods under §§ 1.263A-1(h)(2)(i)(D) and 1.263A-2(b)(2)(i)(D), a taxpayer's self-constructed assets are produced on a routine and repetitive basis in the ordinary course of business if the assets are either mass-produced ...or have a high degree of turnover." The IRS further explains that a high degree of turnover means that the costs of production are recovered (i.e., depreciated) over a relatively short period of time. They have designated three years or less to be the acceptable range for this short period of time.

Q. How does this narrow definition of eligible property affect MECO's potential adjustment?

A. MECO does not engage in any significant manufacturing activity, as defined by the IRS, and except for a few limited exceptions of relatively low value, MECO's utility assets have estimated useful lives of greater than three years. Consequently, MECO would have virtually no property eligible for the simplified service cost method. The new regulations also limit the applicability of this method prospectively for MECO, since the Regulations have the force and effect of law.

Q. How does the Revenue Ruling impact taxpayers under the simplified service cost method?

A. Generally, revenue rulings apply retroactively unless the ruling includes a specific statement indicating the extent to which it is to be applied without retroactive effect. The Revenue Ruling did not include such a statement and presumably applies retroactively. Taxpayers have no recourse on the application of the Revenue Ruling except to challenge its retroactivity.

Impact of the Simplified Service Cost Method

Q. How does this impact the 2007 test year ADIT?

A. Based on the IRS guidance to date, MECO's estimated 2007 test year ADIT should not include any adjustment for the potential change in accounting method described above because the change would not result in any reduction in taxes for prior years. Note also that the new regulations would require that any prior year tax return benefits gleaned from the change be reversed and paid back by the tax year ending December 31, 2006. Thus, any potential deferred income taxes related to the accelerated deductions would be completely reversed as of December 31, 2006.

Q. What other options are available to MECO in this regard?

A. In January 2006, the Company filed a protective application for change in accounting method to a facts and circumstances method for allocating overhead costs to self-constructed assets, effective for 2005. The Company and its consultants believe that this protective application will provide MECO more options in determining its prospective cost allocation method, at the point in time when the issues in the original application for the simplified service cost method are resolved. The Company filed its 2005 income tax return without making any adjustment for any new method since the adjustment depends on the resolution of the 2001 application for the simplified service cost method. If any benefit is to be derived by the new method, the Company will have to file an amended income tax return to claim this adjustment when and if it is determinable. Due to these uncertainties, MECO cannot calculate the potential adjustment for 2007 and has not included any related revenue requirements impact of this potential facts and circumstances method in the test year.

RECENT TAX DEVELOPMENTS

The American Jobs Creation Act of 2004

Q. What changes in the tax law apply to MECO in 2007?

A. On October 22, 2004, President Bush signed the American Jobs Creation Act of 2004 ("2004 Act") into law. The new law is comprised of three major elements: 1) tax relief for U.S.-based manufacturing activities, 2) reforms in the taxation of multinational businesses and 3) approximately four dozen more targeted items of business income tax relief. The latter two elements have little impact on MECO's business, but the tax relief for U.S.-based manufacturing activities may have an impact on the Company.

Q. Please describe this provision.

A. The 2004 Act intends to provide tax relief for domestic manufacturers by providing a deduction based on a percentage of income from qualified activities. Eligible taxpayers may claim a 6% deduction from 2007 through 2009. The full 9% deduction is available in 2010 and thereafter.

Q. How does this affect MECO?

A. One of those qualified activities is the production of electricity. As an integrated producer of electricity, MECO generates and delivers electricity to customers. The 2004 Act specifies that only the production of electricity is an eligible activity, and income from the transmission or distribution of electricity will not qualify. Consequently, MECO will be able to take this new deduction as a percentage of income attributable only to the generation of electricity.

Q. How will the Company determine this income and segregate it from the income attributable to the Company's other activities?

A. Proposed regulations under IRC §199 were issued on October 20, 2005. The proposed regulations state that an integrated producer, such as MECO, that produces and delivers electricity, must allocate its gross receipts between (1) production, which qualifies as domestic production gross receipts ("DPGR"), and (2) distribution and transmission, which do not qualify as DPGR. Treasury Regulation §1.199-4 provides that cost of goods sold must be allocated specifically to the qualified gross receipts and all other indirect costs should be allocated or apportioned using the guidelines set forth in IRC §861. Based on this guidance and in conjunction with the preparation of the 2005 income tax returns, MECO calculated its qualified production activities income (QPAI) and concluded that it would not yield a IRC §199 deduction. No deduction was taken in the 2005 federal income tax return.

Q. What additional guidance has the IRS given since the proposed regulations were issued and, as a result, has MECO changed its IRC §199 deduction computation?

A. The IRS issued final regulations on May 24, 2006 and the guidance given on what is DPGR has led MECO to change its computation. The change involves carving out the generation revenues received for that portion related to purchased power. Treasury regulation §1.199-3(a)(1)(iii) specifies that qualified production must be produced by the taxpayer and therefore revenues received to recover the cost of purchased power should be excluded from DPGR. Correspondingly, the related purchased power expenses should also be excluded from the calculation of QPAI (the base on which the % deduction is applied).

Q. What is the Company's estimate of the impact of IRC §199 on income tax expense?

A. Based on MECO's last cost of service study, 76% of total electric revenue was for the generation function. Using actual 2005 tax return information and factoring in the purchased power carve out, MECO did not qualify for an IRC §199 deduction since QPAI, or income related to MECO generation, was a loss. Consequently, no IRC §199 deduction was included in the 2007 test year. See MECO-WP-1302, pages 5 and 6.

MECO has not had the opportunity to recalculate the IRC §199 deduction under present and proposed rates in this direct submission, but the change in the generation allocation in the cost of service study and the additional revenues at proposed rates is expected to generate some IRC §199 deduction. In addition, based on issues raised in the Hawaii Electric Light Company, Inc. Docket No. 05-0315, MECO will review its calculation and potentially revise its computation and estimated impact on revenue requirements at the next opportunity.

<u>The Energy Tax Incentives Act of 2005</u>

Q. Please describe other recent legislation that may affect the computation of income taxes in this docket.

A. On August 8, 2005, President Bush signed the 2005 Energy Tax Act into law. Generally, the law contains $14.5 billion in tax cuts to effectuate domestic energy conservation at every level. The new law is comprised of four approaches to produce long-term, energy saving initiatives: 1) conservation, 2) development of alternative energy, 3) improving the U.S. energy infrastructure, and 4) production of domestic energy.

Q. How does the 2005 Energy Tax Act affect MECO in 2007?

A. The 2005 Energy Tax Act provides that certain property used in the transmission of 69 or more kilovolts of electricity for sale be depreciated over a shorter 15-year period than the previously established 20-year recovery period. This provision applies to property the original use of which begins after April 11, 2005. MECO has reflected this provision in its estimated 2007 tax depreciation calculations and accumulated deferred tax liability.

<u>The Pension Protection Act of 2006</u>

Q. How has the passage of the Pension Protection Act of 2006 impacted the 2007 test year estimates?

A. The Pension Protection Act signed into law on August 17, 2006 primarily focused on individual retirement plans and provided for more flexibility in funding for one's retirement. Certain provisions affecting employer-sponsored plan funding has no effect on the 2007 test year pension costs since the funding provisions are effective in 2008. Similarly, the provisions have no effect on test year tax expense and deferred income taxes.

<u>FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes</u>

Q. Please describe the newly issued FASB Interpretation No. 48 (FIN 48).

A. The Financial Accounting Standards Board (FASB) was concerned that FAS 109, Accounting for Income Taxes, provided no specific guidance on how to address uncertainty, resulting in diverse accounting practices in reporting the recognition, de-recognition and measurement of benefits related to income taxes. The FASB consequently issued FIN 48 in July 2006 with the objective of providing specific guidance in dealing with the uncertainty of determining and reporting income tax expense related to uncertain tax positions.

Q. What is the effective date for the application of FIN 48?

A. The rules under FIN 48 are effective for years starting after December 15, 2006, and in MECO's case, FIN 48 will be effective for the first quarter of 2007.

Q. How does FIN 48 affect the reporting of income taxes related to uncertain tax positions?

A. The objective of FIN 48 is to increase the relevance and comparability in financial reporting of income taxes and consequently, it provides a two step evaluation process for all uncertain tax positions taken in previously filed income tax returns and planned to be taken in the current year's returns. Before taking these steps, a company must first identify all tax positions for which there may be some doubt as to its sustainability against challenge by tax authorities. Once these positions are identified, the two tiered analysis is performed.

Q. What is the first step in the FIN 48 evaluation?

A. For each uncertain tax position, the Company must decide whether it is "more likely than not" that the position will be sustained upon examination. Generally, the "more likely than not" standard equates to a greater than 50% probability of success by the taxpayer. If a position does not meet this threshold, then the benefit cannot be recognized for financial statement purposes and no further measurement analysis is necessary. The financial statement impact will be summarized below, covering the effects of recording a FIN 48 adjustment.

If a position does meet the "more likely than not threshold," then the reporting entity goes to step two of the analysis process.

Q. What is entailed in step two of the FIN 48 evaluation?

A. Step two of the evaluation involves the determination of the amount of tax benefit recognition on the financial statements. FIN 48 provides a methodology for computing the amount of benefit to be recorded for an uncertain position that has met the threshold in step one. It asks the company to identify the various possible estimated dollar outcomes of the position, then to assess the probability of each possible outcome, starting with the most beneficial outcome to the least beneficial outcome. The cumulative probabilities would total 100%. The benefit recognized is that outcome at which the cumulative probabilities exceed 50%. This methodology is best understood through an example. Paragraph 21 of Appendix A of FIN 48 illustrates the calculation required in step two. See MECO-WP-1305, page 7 of 7.

Q. How does the determination of the recognizable tax benefit under step two impact the financial statements?

A. Step two determines the recognizable benefit, and the FIN 48 adjustment would represent the shortfall between 100% of the benefit and the recognizable benefit. It represents management's quantification of the amount of tax liability or refundable that was not or will not be reflected in the company's income tax returns. The adjustment amount essentially represents a probability "discount" or reserve on the tax return positions and is based on the specific guidelines set forth under FIN 48.

Q. How does FIN 48 address the adjustments for positions that are temporary differences?

A. FIN 48 requires that the adjustments on uncertain tax positions be segregated from the related deferred income tax liability where the position has only timing consequences (a temporary difference for which deferred income taxes are provided). The balance sheet impact generally would be a reclassification between deferred income tax liability and "other tax liabilities" or a gross up of deferred income taxes and "other tax liabilities." In either case, the deferred income taxes and the other tax liabilities would offset each other, netting to zero on the balance sheet.

Q. What is the impact of the adjustments for positions that are potentially permanent differences?

A. If the position is not of a temporary nature, then the adjustment would generally flow to the income statement as a tax expense or benefit. However, in the year FIN 48 is implemented, this adjustment will be reflected as a one-time adjustment to retained earnings.

Q. What other impacts does FIN 48 have on the financial statements?

A. Under FIN 48, a taxpayer is required to accrue interest and penalties for which, under relevant law, the taxpayer would be liable, based on the FIN 48 adjustments. FIN 48 allows the taxpayer to classify the interest and penalties as part of the FIN 48 tax liability or as a discrete item separate from the related taxes.

Q. How does the Company propose to treat the "other non-current tax liabilities" created by the implementation of FIN 48 in the 2007 test year?

A. MECO proposes to treat these non-current tax liabilities as adjustments to rate base, to the extent these adjustments are related to positions that are temporary differences for which deferred income tax liabilities are provided. In these cases, the FIN 48 adjustment will typically result in an increase in FIN 48 non-current tax liability and a corresponding decrease in deferred income tax liability. The differences between tax return reporting and FIN 48 will be temporary differences that do not affect the aggregate taxes paid over time but only affect the timing of when those taxes are paid. In these cases, the inclusion of the FIN 48 liability in rate base will keep post-FIN 48 rate base measurement with respect to tax related items consistent with the pre-FIN 48 measurement.

Q. How does the Company propose to treat a FIN 48 liability or asset that is created by a permanent difference?

A. In a small number of cases, the FIN 48 adjustment may be derived from a permanent difference, which is an item of income or expense that is permanently included for book and not for tax, or vice versa. In this instance, the difference would not be temporary over time, and there would not be an offsetting entry to deferred income taxes. Consequently, the tax effect will flow through income as a estimated reserve item and rate base should not include the associated non-current liability or asset.

Q. Under what condition will the inclusion in rate base of a FIN 48 adjustment related to permanent items be reasonable?

A. The inclusion in rate base is reasonable only if the related expense or benefit is included as part of the cost of service for ratemaking purposes. This position is consistent with the established treatment of deferred income taxes (cost of service includes deferred income tax expense and accordingly, deferred income tax liability reduces rate base).

Q. What should be the rate base treatment for the accrued interest on the other non-current tax liabilities related to the FIN 48 adjustments?

A. The accrued interest on the FIN 48 liability should be excluded from rate base, similar to the adjustments related to positions with permanent book tax consequences. If the interest accrued is included in MECO's cost of service, then it would be appropriate to include in rate base the accrued liability for FIN 48 interest.

Q. Has MECO completed evaluating the impact of FIN 48?

A. No. MECO is in the process of evaluating its uncertain tax positions and their impact on the implementation of FIN 48. MECO has not yet quantified the estimated impact, but it is not expected to be material to the financial statements. Consequently, MECO has not included any effects of FIN 48 implementation in the 2007 test year estimates of cost of service and rate base.

Other Tax Changes

Q. For working cash purposes, what assumptions were made regarding the timing of the payment of estimated income taxes during the test year?

A. Based on proposed Treasury Regulations §1.6655-2 issued in December 2005, estimated taxes are expected to be paid on a more ratable basis than in prior years.

Q. Why do these regulations result in ratable estimated income tax payments?

A. The regulations provide guidance on how taxpayers should calculate their estimated income tax payments and more specifically, on the timing of the recognition of income and expenses incurred in the taxable year in the calculation of taxpayers' estimated taxable income. Based on these proposed rules, MECO will essentially lose the ability to accelerate its deduction of certain state taxes in the calculation of its estimated federal taxes in the first three quarters of the year.

This will result in more level payments of estimated income taxes in each quarter of the taxable year.

Q. Why were income tax payments adjusted for both federal and state purposes when these proposed regulations are federal regulations?

A. Hawaii previously adopted IRC §6655(d) and (e), to which the proposed regulations relate. Consequently, the federal regulations would provide the same guidance to the Hawaii statute on calculating the required estimated income tax payments.

Q. Does this conclude your testimony?

A. Yes, it does.

LON K. OKADA

EDUCATION AND EXPERIENCE BACKGROUND

Business Address:	Hawaiian Electric Industries, Inc. 220 South King Street, Suite 1710 Honolulu, Hawaii 96813
Current Position:	Manager of Taxes (17 years)
Previous Positions:	Manager of Taxes and Depreciation Hawaiian Electric Company, Inc. (1 year) Director of Taxes and Depreciation Hawaiian Electric Company, Inc. (5 years) Tax Manager, Coopers & Lybrand (5 years) Senior Assistant Accountant, Deloitte Haskins & Sells (2 years)
Education:	Bachelor of Science, Business Administration Graduated Magna Cum Laude University of Southern California Juris Doctor Hastings College of the Law, University of California
Other Qualifications:	Certified Public Accountant, Hawaii and California Member of the State Bar, Hawaii and California
Previous Testimony:	Docket No. 5658--Depreciation Adjustment Income Tax Calculation Docket Nos. 6432, 6531, 6998, 6999, 7000, 7764, 99-0207, and 04-0113 — HECO, HELCO, and MECO Rate Cases Taxes Other than Income Taxes, Income Tax Expense, Unamortized Investment Tax Credits, Accumulated Deferred Income Taxes and Net SFAS 109 Regulatory Assets

Maui Electric Company, Ltd.
Taxes Other Than Income Charged to Operations
Test Year 2007
(In thousands)

		(A) At Current Effective Rates	(B) Changes	(C) At Proposed Rates	References
	Maui				
	Payroll Taxes				
1	FICA Taxes	1,196		1,196	
2	Federal Unemployment Taxes	12		12	
3	State Unemployment Taxes	45		45	
4	Total Payroll Taxes	1,253	-	1,253	
	Revenue Taxes				
5	Public Service Company Taxes	19,672	1,044	20,716	
6	Public Utility Fees	1,671	89	1,760	
7	Franchise Royalty Taxes	8,322	439	8,761	
8	Total Revenue Taxes	29,665	1,572	31,237	
9	Total Taxes Other Than Income Taxes	30,918	1,572	32,490	
	Lanai				
	Payroll Taxes				
10	FICA Taxes	53		53	
11	Federal Unemployment Texes	1		1	
12	State Unemployment Taxes	2		2	
13	Total Payroll Taxes	56	-	56	
	Revenue Taxes				
14	Public Service Company Taxes	594	32	626	
15	Public Utility Fees	50	3	53	
16	Franchise Royalty Taxes	252	13	265	
17	Total Revenue Taxes	896	48	944	
18	Total Taxes Other Than Income Taxes	952	48	1,000	
	Molokai				
	Payroll Taxes				
19	FICA Taxes	66		66	
20	Federal Unemployment Texes	1		1	
21	State Unemployment Taxes	2		2	
22	Total Payroll Taxes	69	-	69	
	Revenue Taxes				
23	Public Service Company Taxes	749	40	789	
24	Public Utility Fees	64	3	67	
25	Franchise Royalty Taxes	316	17	333	
26	Total Revenue Taxes	1,129	60	1,189	
27	Total Taxes Other Than Income Taxes	1,198	60	1,258	
	TOTAL MECO				
	Payroll Taxes				
28	FICA Taxes	1,315	-	1,315	
29	Federal Unemployment Texes	14	-	14	
30	State Unemployment Taxes	49	-	49	
31	Total Payroll Taxes	1,378	-	1,378	MECO-WP-1301
	Revenue Taxes				
32	Public Service Company Taxes	21,015	1,116	22,131	
33	Public Utility Fees	1,785	95	1,880	
34	Franchise Royalty Taxes	8,890	469	9,359	
35	Total Revenue Taxes	31,690	1,680	33,370	
36	Total Taxes Other Than Income Taxes	33,068	1,680	34,748	

Maui Electric Company, Ltd.
Computation of Income Tax Expense
Test Year 2007

(In Thousands)

		(A) At Present Rates	(B) Adjustment	(C) At Proposed Rates	References
	MAUI				
1	Total Operating Revenues	334,465	17,757	352,222	
	Operating Expenses:				
2	Fuel Oil and Purchased Power	201,018		201,018	
3	Other Operation & Maint Exp	43,696	11	43,707	
4	Depreciation & Amortization	26,598		26,598	MECO-1201
5	Amortization of State ITC	(475)		(475)	MECO 1304
6	Taxes Other Than Income Taxes	30,918	1,572	32,490	MECO-1301
7	Other Interest, Net	216		216	
8	Total Operating Expenses	301,971	1,583	303,554	
9	Operating Income Before Taxes	32,494	16,174	48,668	
	Tax Adjustments:				
10	Interest Expense	(9,078)		(9,078)	MECO-WP-1302
11	Meals & Entertainment	29		29	MECO-WP-1302
12	Total Tax Adjustments	(9,049)	-	(9,049)	
13	Taxable Income for Rate-Making	23,445	16,174	39,619	
14	Composite Effective Income Tax Rate	38.9097744%	38.9097744%	38.9097744%	
15	TOTAL INCOME TAX EXPENSE	9,122	6,293	15,415	
	LANAI				
16	Total Operating Revenues	10,105	539	10,644	
	Operating Expenses:				
17	Fuel Oil and Purchased Power	6,176		6,176	
18	Other Operation & Maint Exp	1,823	-	1,823	
19	Depreciation & Amortization	1,243		1,243	MECO-1201
20	Amortization of State ITC	(20)		(20)	MECO 1304
21	Taxes Other Than Income Taxes	952	48	1,000	MECO-1301
22	Other Interest, Net	6		6	
23	Total Operating Expenses	10,180	48	10,228	
24	Operating Income Before Taxes	(75)	491	416	
	Tax Adjustments:				
25	Interest Expense	(377)		(377)	MECO-WP-1302
26	Meals & Entertainment	1		1	MECO-WP-1302
27	Total Tax Adjustments	(376)	-	(376)	
28	Taxable Income for Rate-Making	(451)	491	40	
29	Composite Effective Income Tax Rate	38.9097744%	38.9097744%	38.9097744%	
30	TOTAL INCOME TAX EXPENSE	(175)	191	16	

Maui Electric Company, Ltd.
Computation of Income Tax Expense
Test Year 2007

(In Thousands)

		(A) At Present Rates	(B) Adjustment	(C) At Proposed Rates	
	MOLOKAI				
1	Total Operating Revenues	12,738	681	13,419	
	Operating Expenses:				
2	Fuel Oil and Purchased Power	7,253		7,253	
3	Other Operation & Maint Exp	2,510	-	2,510	
4	Depreciation & Amortization	1,031		1,031	MECO-1201
5	Amortization of State ITC	(23)		(23)	MECO 1304
6	Taxes Other Than Income Taxes	1,198	60	1,258	MECO-1301
7	Other Interest, Net	11		11	
8	Total Operating Expenses	11,980	60	12,040	
9	Operating Income Before Taxes	758	621	1,379	
	Tax Adjustments:				
10	Interest Expense	(440)		(440)	MECO-WP-1302
11	Meals & Entertainment	1		1	MECO-WP-1302
12	Total Tax Adjustments	(439)	-	(439)	
13	Taxable Income for Rate-Making	319	621	940	
14	Composite Effective Income Tax Rate	38.9097744%	38.9097744%	38.9097744%	
15	TOTAL INCOME TAX EXPENSE	124	242	366	
	TOTAL MECO				
16	Total Operating Revenues	357,308	18,977	376,285	
	Operating Expenses:				
17	Fuel Oil and Purchased Power	214,447	-	214,447	
18	Other Operation & Maint Exp	48,029	11	48,040	
19	Depreciation & Amortization	28,872	-	28,872	MECO-1201
20	Amortization of State ITC	(518)	-	(518)	MECO 1304
21	Taxes Other Than Income Taxes	33,068	1,680	34,748	MECO-1301
22	Other Interest, Net	233	-	233	
23	Total Operating Expenses	324,131	1,691	325,822	
24	Operating Income Before Taxes	33,177	17,286	50,463	
	Tax Adjustments:				
25	Interest Expense	(9,895)	-	(9,895)	MECO-WP-1302
26	Meals & Entertainment	31	-	31	MECO-WP-1302
27	Total Tax Adjustments	(9,864)	-	(9,864)	
28	Taxable Income for Rate-Making	23,313	17,286	40,599	
29	Composite Effective Income Tax Rate	38.9097744%	38.9097744%	38.9097744%	
30	TOTAL INCOME TAX EXPENSE	9,071	6,726	15,797	

Maui Electric Company, Ltd.
Federal Investment Tax Credit
For Years 2001 - 2007

(In Thousands)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Actual 2001	Actual 2002	Actual 2003	Actual 2004	Actual 2005	Estimate 2006	Test Year 2007
	MAUI							
	1962 Revenue Act							
1	Beginning Balance	-	-	-	-	-	-	-
2	Amortization	-	-	-	-	-	-	-
3	Ending Balance	-	-	-	-	-	-	-
4	Average Balance							-
	1971 Revenue Act							
5	Beginning Balance	2,606	2,346	2,086	1,830	1,581	1,337	1,115
6	Amortization	(260)	(260)	(256)	(249)	(244)	(222)	(212)
7	Ending Balance	2,346	2,086	1,830	1,581	1,337	1,115	903
	Amortization							
8	1962 Revenue Act	-	-	-	-	-	-	-
9	1971 Revenue Act	(260)	(260)	(256)	(249)	(244)	(222)	(212)
10	Total Amortization	(260)	(260)	(256)	(249)	(244)	(222)	(212)
	LANAI							
	1962 Revenue Act							
11	Beginning Balance	-	-	-	-	-	-	-
12	Amortization	-	-	-	-	-	-	-
13	Ending Balance	-	-	-	-	-	-	-
14	Average Balance							-
	1971 Revenue Act							
15	Beginning Balance	20	18	16	14	12	10	8
16	Amortization	(2)	(2)	(2)	(2)	(2)	(2)	(2)
17	Ending Balance	18	16	14	12	10	8	6
	Amortization							
18	1962 Revenue Act	-	-	-	-	-	-	-
19	1971 Revenue Act	(2)	(2)	(2)	(2)	(2)	(2)	(2)
20	Total Amortization	(2)	(2)	(2)	(2)	(2)	(2)	(2)

Maui Electric Company, Ltd.
Federal Investment Tax Credit
For Years 2001 - 2007

(In Thousands)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Actual 2001	Actual 2002	Actual 2003	Actual 2004	Estimate 2005	Estimate 2006	Test Year 2007
	MOLOKAI							
	1962 Revenue Act							
1	Beginning Balance	-	-	-	-	-	-	-
2	Amortization	-	-	-	-	-	-	-
3	Ending Balance	-	-	-	-	-	-	-
4	Average Balance							-
	1971 Revenue Act							
5	Beginning Balance	-	-	-	-	-	-	-
6	Amortization	-	-	-	-	-	-	-
7	Ending Balance	-	-	-	-	-	-	-
	Amortization							
8	1962 Revenue Act	-	-	-	-	-	-	-
9	1971 Revenue Act	-	-	-	-	-	-	-
10	Total Amortization	-	-	-	-	-	-	-
	TOTAL MECO							
	1962 Revenue Act							
11	Beginning Balance	-	-	-	-	-	-	-
12	Amortization	-	-	-	-	-	-	-
13	Ending Balance	-	-	-	-	-	-	-
14	Average Balance							-
	1971 Revenue Act							
15	Beginning Balance	2,626	2,364	2,102	1,844	1,593	1,347	1,123
16	Amortization	(262)	(262)	(258)	(251)	(246)	(224)	(214)
17	Ending Balance	2,364	2,102	1,844	1,593	1,347	1,123	909
	Amortization							
18	1962 Revenue Act	-	-	-	-	-	-	-
19	1971 Revenue Act	(262)	(262)	(258)	(251)	(246)	(224)	(214)
20	Total Amortization	(262)	(262)	(258)	(251)	(246)	(224)	(214)

Maui Electric Company, Ltd.
State Capital Goods Excise Tax Credit
For Years 2001-2007

(In Thousands)

		Actual 2001	Actual 2002	Actual 2003	Actual 2004	Actual 2005	Estimate 2006	**Test Year 2007**
	MAUI							
1	Beginning Balance	7,177	8,225	8,241	8,153	9,099	9,246	**10,244**
2	Amortization	(294)	(308)	(323)	(381)	(410)	(427)	**(475)**
3	Additions (Net of Recap)	1,342	324	235	1,327	557	1,425	**545**
4	Ending Balance	8,225	8,241	8,153	9,099	9,246	10,244	**10,314**
5	Average Balance (At Gross)							**10,279**
6	Amortization at Gross of Taxes				381	410	427	**475**
7	Amortization , Net of State Taxes*	294	308	323				
	LANAI							
8	Beginning Balance	298	342	342	339	378	384	**426**
9	Amortization	(12)	(13)	(13)	(16)	(17)	(18)	**(20)**
10	Additions (Net of Recap)	56	13	10	55	23	60	**23**
11	Ending Balance	342	342	339	378	384	426	**429**
12	Average Balance (At Gross)							**428**
13	Amortization at Gross of Taxes				16	17	18	**20**
14	Amortization , Net of State Taxes*	12	13	13				

* NOTE: Prior to 2004, the unamortized state capital goods excise tax credit was shown net of state taxes in the general ledger. In 2004, the balance was grossed up and the state tax effect was reclassified to the accumulated state deferred income tax liability account.

Maui Electric Company, Ltd.
State Capital Goods Excise Tax Credit
For Years 2001-2007

(In Thousands)

		Actual 2001	Actual 2002	Actual 2003	Actual 2004	Actual 2005	Estimate 2006	**Test Year 2007**
	MOLOKAI							
1	Beginning Balance	348	399	400	395	441	448	**497**
2	Amortization	(14)	(15)	(16)	(18)	(20)	(21)	**(23)**
3	Additions (Net of Recap)	65	16	11	64	27	70	**26**
4	Ending Balance	399	400	395	441	448	497	**500**
5	Average Balance (At Gross)							**499**
6	Amortization at Gross of Taxes				18	20	21	**23**
7	Amortization , Net of State Taxes*	14	15	16				
	TOTAL MECO							
8	Beginning Balance	7,823	8,966	8,983	8,887	9,918	10,078	**11,167**
9	Amortization	(320)	(336)	(352)	(415)	(447)	(466)	**(518)**
10	Additions (Net of Recap)	1,463	353	256	1,446	607	1,555	**594**
11	Ending Balance	8,966	8,983	8,887	9,918	10,078	11,167	**11,243**
12	Average Balance (At Gross)							**11,205**
13	Amortization at Gross of Taxes				415	447	466	**518**
14	Amortization , Net of State Taxes*	320	336	352				

* NOTE: Prior to 2004, the unamortized state capital goods excise tax credit was shown net of state taxes in the general ledger. In 2004, the balance was grossed up and the state tax effect was reclassified to the accumulated state deferred income tax liability account.

Maui Electric Company, Ltd.
Deferred Income Taxes by Individual
Item and Year-End Balances
For Years 2001 - 2007

(In Thousands)

		Actual Balance 12/31/2000	Actual 2001 Net Add/(Amort)	Actual Balance 12/31/2001	Actual 2002 Net Add/(Amort)	Actual Balance 12/31/2002	Actual 2003 Net Add/(Amort)	Actual Balance 12/31/2003
	MAUI							
	Accelerated Depreciation Over Straight-Line							
1	Federal	11,333	(687)	10,646	1,598	12,244	(402)	11,842
2	State	2,212	(20)	2,192	(48)	2,144	(142)	2,002
3	Subtotal	13,545	(707)	12,838	1,550	14,388	(544)	13,844
	All Other Items							
4	Federal	(3,614)	1,122	(2,492)	(344)	(2,836)	1,256	(1,580)
5	State	(186)	260	74	(62)	12	224	236
6	Subtotal	(3,800)	1,382	(2,418)	(406)	(2,824)	1,480	(1,344)
7	Total	9,745	675	10,420	1,144	11,564	936	12,500
8	Average Balance							
	LANAI							
	Accelerated Depreciation Over Straight-Line							
9	Federal	471	(28)	443	66	509	(17)	492
10	State	92	(1)	91	(2)	89	(6)	83
11	Subtotal	563	(29)	534	64	598	(23)	575
	All Other Items							
12	Federal	(150)	47	(103)	(14)	(117)	52	(65)
13	State	(8)	11	3	(3)	-	9	9
14	Subtotal	(158)	58	(100)	(17)	(117)	61	(56)
15	Total	405	29	434	47	481	38	519
16	Average Balance							

Source: MECO-WP-1305

Maui Electric Company, Ltd.
Deferred Income Taxes by Individual
Item and Year-End Balances
For Years 2001 - 2007

(In Thousands)

		Actual Balance 12/31/2000	Actual 2001 Net Add/(Amort)	Actual Balance 12/31/2001	Actual 2002 Net Add/(Amort)	Actual Balance 12/31/2002	Actual 2003 Net Add/(Amort)	Actual Balance 12/31/2003
	MOLOKAI							
	Accelerated Depreciation Over Straight-Line							
17	Federal	550	(33)	517	78	595	(20)	575
18	State	107	(1)	106	(2)	104	(7)	97
19	Subtotal	657	(34)	623	76	699	(27)	672
	All Other Items							
20	Federal	(175)	54	(121)	(17)	(138)	61	(77)
21	State	(9)	13	4	(3)	1	11	12
22	Subtotal	(184)	67	(117)	(20)	(137)	72	(65)
23	Total	473	33	506	56	562	45	607
24	Average Balance							
	TOTAL MECO							
	Accelerated Depreciation Over Straight-Line							
25	Federal	12,354	(748)	11,606	1,742	13,348	(439)	12,909
26	State	2,411	(22)	2,389	(52)	2,337	(155)	2,182
27	Subtotal	14,765	(770)	13,995	1,690	15,685	(594)	15,091
	All Other Items							
28	Federal	(3,939)	1,223	(2,716)	(375)	(3,091)	1,369	(1,722)
29	State	(203)	284	81	(68)	13	244	257
30	Subtotal	(4,142)	1,507	(2,635)	(443)	(3,078)	1,613	(1,465)
31	Total	10,623	737	11,360	1,247	12,607	1,019	13,626
32	Average Balance							

Source: MECO-WP-1305

Maui Electric Company, Ltd.
Deferred Income Taxes by Individual
Item and Year-End Balances
For Years 2001 - 2007

(In Thousands)

		Actual Balance 12/31/2003	Actual 2004 Net Add/(Amort)	Actual Balance 12/31/2004	Actual 2005 Net Add/(Amort)	Actual Balance 12/31/2005	Estimated 2006 Net Add/(Amort)	Estimated Balance 12/31/2006
	MAUI							
	Accelerated Depreciation Over Straight-Line							
1	Federal	11,842	3,700	15,542	(1,344)	14,198	(1,517)	12,681
2	State	2,002	(109)	1,893	(172)	1,721	(201)	1,520
3	Subtotal	13,844	3,591	17,435	(1,516)	15,919	(1,718)	14,201
	All Other Items							
4	Federal	(1,580)	1,960	380	4,270	4,650	(132)	4,518
5	State	236	(185)	51	810	861	(24)	837
6	Subtotal	(1,344)	1,775	431	5,080	5,511	(156)	5,355
7	Total	12,500	5,366	17,866	3,564	21,430	(1,874)	19,556
8	Average Balance							
	LANAI							
	Accelerated Depreciation Over Straight-Line							
9	Federal	492	154	646	(56)	590	(63)	527
10	State	83	(4)	79	(7)	72	(8)	64
11	Subtotal	575	150	725	(63)	662	(71)	591
	All Other Items							
12	Federal	(65)	81	16	177	193	(5)	188
13	State	9	(8)	1	34	35	(1)	34
14	Subtotal	(56)	73	17	211	228	(6)	222
15	Total	519	223	742	148	890	(77)	813
16	Average Balance							

Source: MECO-WP-1305

Maui Electric Company, Ltd.
Deferred Income Taxes by Individual
Item and Year-End Balances
For Years 2001 - 2007

(In Thousands)

		Actual Balance 12/31/2003	Actual 2004 Net Add/(Amort)	Actual Balance 12/31/2004	Actual 2005 Net Add/(Amort)	Actual Balance 12/31/2005	Estimated 2006 Net Add/(Amort)	Estimated Balance 12/31/2006
	MOLOKAI							
	Accelerated Depreciation Over Straight-Line							
17	Federal	575	179	754	(65)	689	(74)	615
18	State	97	(5)	92	(8)	84	(10)	74
19	Subtotal	672	174	846	(73)	773	(84)	689
	All Other Items							
20	Federal	(77)	95	18	207	225	(6)	219
21	State	12	(9)	3	39	42	(1)	41
22	Subtotal	(65)	86	21	246	267	(7)	260
23	Total	607	260	867	173	1,040	(91)	949
24	Average Balance							

		Actual Balance 12/31/2003	Actual 2004 Net Add/(Amort)	Actual Balance 12/31/2004	Actual 2005 Net Add/(Amort)	Actual Balance 12/31/2005	Estimated 2006 Net Add/(Amort)	Estimated Balance 12/31/2006
	TOTAL MECO							
	Accelerated Depreciation Over Straight-Line							
25	Federal	12,909	4,033	16,942	(1,465)	15,477	(1,654)	13,823
26	State	2,182	(118)	2,064	(187)	1,877	(219)	1,658
27	Subtotal	15,091	3,915	19,006	(1,652)	17,354	(1,873)	15,481
	All Other Items							
28	Federal	(1,722)	2,136	414	4,654	5,068	(143)	4,925
29	State	257	(202)	55	883	938	(26)	912
30	Subtotal	(1,465)	1,934	469	5,537	6,006	(169)	5,837
31	Total	13,626	5,849	19,475	3,885	23,360	(2,042)	21,318
32	Average Balance							

Source: MECO-WP-1305

Maui Electric Company, Ltd.
Deferred Income Taxes by Individual
Item and Year-End Balances
For Years 2001 - 2007

(In Thousands)

		Estimated Balance 12/31/2006	Estimated 2007 Net Add/(Amort)	Estimated Balance 12/31/2007	
	MAUI				
	Accelerated Depreciation Over Straight-Line				
1	Federal	12,681	(897)	11,784	
2	State	1,520	(79)	1,441	
3	Subtotal	14,201	(976)	13,225	
	All Other Items				
4	Federal	4,518	(638)	3,880	
5	State	837	(114)	723	
6	Subtotal	5,355	(752)	4,603	
7	Total	19,556	(1,728)	17,828	
8	Corrected Average Balance			18,692	
	Adjustment to Revenue Requirements			131	*
	Avg Bal per Revenue Requirements run			18,823	
	LANAI				
	Accelerated Depreciation Over Straight-Line				
9	Federal	527	(37)	490	
10	State	64	(3)	61	
11	Subtotal	591	(40)	551	
	All Other Items				
12	Federal	188	(26)	162	
13	State	34	(5)	29	
14	Subtotal	222	(31)	191	
15	Total	813	(71)	742	
16	Corrected Average Balance			778	
	Adjustment to Revenue Requirements			4	*
	Avg Bal per Revenue Requirements run			782	

Source: MECO-WP-1305

* Adjustments to the average deferred income tax balances included in revenue requirements will be revised at the next earliest opportunity.

Maui Electric Company, Ltd.
Deferred Income Taxes by Individual
Item and Year-End Balances
For Years 2001 - 2007

(In Thousands)

		Estimated Balance 12/31/2006	Estimated 2007 Net Add/(Amort)	Estimated Balance 12/31/2007	
	MOLOKAI				
	Accelerated Depreciation Over Straight-Line				
17	Federal	615	(44)	571	
18	State	74	(4)	70	
19	Subtotal	689	(48)	641	
	All Other Items				
20	Federal	219	(31)	188	
21	State	41	(6)	35	
22	Subtotal	260	(37)	223	
23	Total	949	(85)	864	
24	Corrected Average Balance			907	
	Adjustment to Revenue Requirements			6	*
	Avg Bal per Revenue Requirements run			913	
	TOTAL MECO				
	Accelerated Depreciation Over Straight-Line				
25	Federal	13,823	(978)	12,845	
26	State	1,658	(86)	1,572	
27	Subtotal	15,481	(1,064)	14,417	
	All Other Items				
28	Federal	4,925	(695)	4,230	
29	State	912	(125)	787	
30	Subtotal	5,837	(820)	5,017	
31	Total	21,318	(1,884)	19,434	
32	Corrected Average Balance			20,376	
	Adjustment to Revenue Requirements			142	*
	Avg Bal per Revenue Requirements run			20,518	

Source: MECO-WP-1305

* Adjustments to the average deferred income tax balances included in revenue requirements will be revised at the next earliest opportunity.

(In Thousands)

	Description	(A) Actual Balance 12/31/2005	(B) Est 2006 Adds	(C) Est 2006 Amort	(D) Est Balance 12/31/2006	(E) Est 2007 Adds	(F) Est 2007 Amort	(G) Est Balance 12/31/2007	
	MAUI								
1	CWIP Equity Transition	334	-	(27)	307	-	(25)	282	
2	*SFAS 109 Flow-Through*	*84*	-	*(29)*	*54*	-	*(26)*	29	
3	Plant Transition	735	-	(86)	649	-	(86)	563	
4	CWIP Equity	6,728	1,166	(366)	7,528	262	(389)	7,401	
5	Federal ITC	(767)	-	128	(639)	-	122	(518)	*
6	Excess AccDep	(132)	-	132	-	-	-	-	
7	Deficit AccDep	241	-	(35)	206	-	(35)	171	
8	Deficit Deferred Tax	(57)	-	7	(50)	-	7	(44)	
9	Excess Deferred Tax	5	-	(3)	3	-	(3)	-	
10	Total	7,171	1,166	(280)	8,058	262	(434)	7,885	
11	Average							7,972	

	Description	(A) Actual Balance 12/31/2005	(B) Est 2006 Adds	(C) Est 2006 Amort	(D) Est Balance 12/31/2006	(E) Est 2007 Adds	(F) Est 2007 Amort	(G) Est Balance 12/31/2007	
	LANAI								
12	CWIP Equity Transition	18	-	(1)	16	-	(1)	15	
13	SFAS 109 Flow-Through	4	-	(2)	3	-	(1)	2	
14	Plant Transition	39	-	(5)	34	-	(5)	30	
15	CWIP Equity	354	61	(19)	396	33	(20)	409	
16	Federal ITC	(40)	-	7	(34)	-	6	(27)	*
17	Excess AccDep	(7)	-	7	-	-	-	-	
18	Deficit AccDep	13	-	(2)	11	-	(2)	9	
19	Deficit Deferred Tax	(3)	-	0	(3)	-	0	(2)	
20	Excess Deferred Tax	0	-	(0)	0	-	(0)	-	
21	Total	378	61	(15)	424	33	(23)	434	
22	Average							429	

* Amortization of Federal ITC was indavertently allocated to Molokai in detemining revenue requirements. The total amount should be allocated between Maui and Lanai only. The allocation will be revised at the next earliest opportunity.

(In Thousands)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	
	Description	Actual Balance 12/31/2005	Est 2006 Adds	Est 2006 Amort	Est Balance 12/31/2006	Est 2007 Adds	Est 2007 Amort	Est Balance 12/31/2007	
	MOLOKAI								
1	CWIP Equity Transition	22	-	(2)	20	-	(2)	18	
2	SFAS 109 Flow-Through	5	-	(2)	4	-	(2)	2	
3	Plant Transition	48	-	(6)	43	-	(6)	37	
4	CWIP Equity	441	76	(24)	493	8	(25)	476	
5	Federal ITC	(50)	-	8	(42)	-	8	(34)	*
6	Excess AccDep	(9)	-	9	-	-	-	-	
7	Deficit AccDep	16	-	(2)	14	-	(2)	11	
8	Deficit Deferred Tax	(4)	-	0	(3)	-	0	(3)	
9	Excess Deferred Tax	0	-	(0)	0	-	(0)	-	
10	Total	470	76	(18)	528	8	(28)	507	
11	Average							518	

		(A)	(B)	(C)	(D)	(E)	(F)	(G)
	Description	Actual Balance 12/31/2005	Est 2006 Adds	Est 2006 Amort	Est Balance 12/31/2006	Est 2007 Adds	Est 2007 Amort	Est Balance 12/31/2007
	TOTAL MECO							
12	CWIP Equity Transition	373	-	(30)	343	-	(28)	315
13	SFAS 109 Flow-Through	94	-	(33)	61	-	(29)	32
14	Plant Transition	822	-	(96)	726	-	(96)	630
15	CWIP Equity	7,523	1,304	(409)	8,418	302	(435)	8,286
16	Federal ITC	(858)	-	143	(715)	-	136	(579)
17	Excess AccDep	(147)	-	147	-	-	-	-
18	Deficit AccDep	270	-	(39)	230	-	(39)	191
19	Deficit Deferred Tax	(64)	-	8	(56)	-	8	(49)
20	Excess Deferred Tax	6	-	(3)	3	-	(3)	-
21	Total	8,019	1,304	(313)	9,010	302	(486)	8,827
22	Average							8,919

* Amortization of Federal ITC was indavertently allocated to Molokai in detemining revenue requirements. The total amount should be allocated between Maui and Lanai only. The allocation will be revised at the next earliest opportunity.

(In Thousands)

	Description	(A) Actual Balance 12/31/2003	(B) Actual 2004 Adds	(C) Actual 2004 Amort	(D) Actual Balance 12/31/2004	(E) Actual 2005 Adds	(F) Actual 2005 Amort	(G) Actual Balance 12/31/2005	
	MAUI								
1	CWIP Equity Transition	389	-	(28)	362	-	(28)	334	
2	SFAS 109 Flow-Through	150	-	(34)	117	-	(33)	84	
3	Plant Transition	918	-	(92)	826	-	(91)	735	
4	CWIP Equity	6,707	231	(356)	6,582	512	(367)	6,728	
5	Federal ITC	(1,050)	-	143	(907)	-	140	(767)	*
6	Excess AccDep	(786)	-	327	(459)	-	327	(132)	
7	Deficit AccDep	312	-	(35)	277	-	(35)	241	
8	Deficit Deferred Tax	-	-	-	-	(64)	7	(57)	
9	Excess Deferred Tax	-	-	-	-	8	(3)	5	
10	Total	6,641	231	(75)	6,797	456	(83)	7,171	
11	Average							6,984	

	Description	(A) Actual Balance 12/31/2003	(B) Actual 2004 Adds	(C) Actual 2004 Amort	(D) Actual Balance 12/31/2004	(E) Actual 2005 Adds	(F) Actual 2005 Amort	(G) Actual Balance 12/31/2005	
	LANAI								
12	CWIP Equity Transition	21	-	(1)	19	-	(1)	18	
13	SFAS 109 Flow-Through	8	-	(2)	6	-	(2)	4	
14	Plant Transition	48	-	(5)	44	-	(5)	39	
15	CWIP Equity	353	12	(19)	347	27	(19)	354	
16	Federal ITC	(55)	-	8	(48)	-	7	(40)	*
17	Excess AccDep	(41)	-	17	(24)	-	17	(7)	
18	Deficit AccDep	16	-	(2)	15	-	(2)	13	
19	Deficit Deferred Tax	-	-	-	-	(3)	0	(3)	
20	Excess Deferred Tax	-	-	-	-	0	(0)	0	
21	Total	350	12	(4)	358	24	(4)	378	
22	Average							368	

* Amortization of Federal ITC was indavertently allocated to Molokai in detemining revenue requirements. The total amount should be allocated between Maui and Lanai only. The allocation will be revised at the next earliest opportunity.

(In Thousands)

	Description	(A) Actual Balance 12/31/2003	(B) Actual 2004 Adds	(C) Actual 2004 Amort	(D) Actual Balance 12/31/2004	(E) Actual 2005 Adds	(F) Actual 2005 Amort	(G) Actual Balance 12/31/2005	
	MOLOKAI								
1	CWIP Equity Transition	26	-	(2)	24	-	(2)	22	
2	SFAS 109 Flow-Through	10	-	(2)	8	-	(2)	5	
3	Plant Transition	60	-	(6)	54	-	(6)	48	
4	CWIP Equity	439	15	(23)	431	34	(24)	441	
5	Federal ITC	(69)	-	9	(59)	-	9	(50)	*
6	Excess AccDep	(52)	-	21	(30)	-	21	(9)	
7	Deficit AccDep	20	-	(2)	18	-	(2)	16	
8	Deficit Deferred Tax	-	-	-	-	(4)	0	(4)	
9	Excess Deferred Tax	-	-	-	-	1	(0)	0	
10	Total	435	15	(5)	445	30	(5)	470	
11	Average							458	

	Description	(A) Actual Balance 12/31/2003	(B) Actual 2004 Adds	(C) Actual 2004 Amort	(D) Actual Balance 12/31/2004	(E) Actual 2005 Adds	(F) Actual 2005 Amort	(G) Actual Balance 12/31/2005
	TOTAL MECO							
12	CWIP Equity Transition	436	-	(31)	404	-	(31)	373
13	SFAS 109 Flow-Through	168	-	(38)	131	-	(37)	94
14	Plant Transition	1,027	-	(102)	924	-	(102)	822
15	CWIP Equity	7,500	258	(398)	7,360	573	(410)	7,523
16	Federal ITC	(1,174)	-	159	(1,014)	-	157	(858)
17	Excess AccDep	(879)	-	366	(513)	-	366	(147)
18	Deficit AccDep	349	-	(40)	309	-	(39)	270
19	Deficit Deferred Tax	-	-	-	-	(72)	8	(64)
20	Excess Deferred Tax	-	-	-	-	9	(3)	6
21	Total	7,426	258	(84)	7,601	510	(92)	8,019
22	Average							7,810

* Amortization of Federal ITC was indavertently allocated to Molokai in detemining revenue requirements. The total amount should be allocated between Maui and Lanai only. The allocation will be revised at the next earliest opportunity.

Maui Electric Company, Ltd.
Regulatory Assets and Liabilities
For Years 2002-2003

(In Thousands)

	Description	(A) Actual Balance 12/31/2001	(B) Actual 2002 Adds	(C) Actual 2002 Amort	(D) Actual Balance 12/31/2002	(E) Actual 2003 Adds	(F) Actual 2003 Amort	(G) Actual Balance 12/31/2003	
	MAUI								
1	CWIP Equity Transition	443	-	(27)	416	-	(27)	389	
2	SFAS 109 Flow-Through	234	-	(49)	185	-	(34)	150	
3	Plant Transition	1,110	-	(100)	1,011	-	(92)	918	
4	CWIP Equity	6,978	127	(318)	6,787	253	(333)	6,707	
5	Federal ITC	(1,346)	-	149	(1,197)	-	147	(1,050)	*
6	Excess AccDep	(1,440)	-	327	(1,113)	-	327	(786)	
7	Deficit AccDep	383	-	(35)	347	-	(35)	312	
8	Deficit Deferred Tax	-	-	-	-	-	-	-	
9	Excess Deferred Tax	-	-	-	-	-	-	-	
10	Total	6,361	127	(52)	6,436	253	(47)	6,641	
11	Average							6,539	

	Description	(A) Actual Balance 12/31/2001	(B) Actual 2002 Adds	(C) Actual 2002 Amort	(D) Actual Balance 12/31/2002	(E) Actual 2003 Adds	(F) Actual 2003 Amort	(G) Actual Balance 12/31/2003	
	LANAI								
12	CWIP Equity Transition	23	-	(1)	22	-	(1)	21	
13	SFAS 109 Flow-Through	12	-	(3)	10	-	(2)	8	
14	Plant Transition	58	-	(5)	53	-	(5)	48	
15	CWIP Equity	368	7	(17)	357	13	(18)	353	
16	Federal ITC	(71)	-	8	(63)	-	8	(55)	*
17	Excess AccDep	(76)	-	17	(59)	-	17	(41)	
18	Deficit AccDep	20	-	(2)	18	-	(2)	16	
19	Deficit Deferred Tax	-	-	-	-	-	-	-	
20	Excess Deferred Tax	-	-	-	-	-	-	-	
21	Total	335	7	(3)	339	13	(2)	350	
22	Average							344	

* Amortization of Federal ITC was indavertently allocated to Molokai in detemining revenue requirements. The total amount should be allocated between Maui and Lanai only. The allocation will be revised at the next earliest opportunity.

Maui Electric Company, Ltd.
Regulatory Assets and Liabilities
For Years 2002-2003

(In Thousands)

	Description	(A) Actual Balance 12/31/2001	(B) Actual 2002 Adds	(C) Actual 2002 Amort	(D) Actual Balance 12/31/2002	(E) Actual 2003 Adds	(F) Actual 2003 Amort	(G) Actual Balance 12/31/2003
	MOLOKAI							
1	CWIP Equity Transition	29	-	(2)	27	-	(2)	26
2	SFAS 109 Flow-Through	15	-	(3)	12	-	(2)	10
3	Plant Transition	73	-	(7)	66	-	(6)	60
4	CWIP Equity	457	8	(21)	445	17	(22)	439
5	Federal ITC	(88)	-	10	(78)	-	10	(69) *
6	Excess AccDep	(94)	-	21	(73)	-	21	(52)
7	Deficit AccDep	25	-	(2)	23	-	(2)	20
8	Deficit Deferred Tax	-	-	-	-	-	-	-
9	Excess Deferred Tax	-	-	-	-	-	-	-
10	Total	417	8	(3)	422	17	(3)	435
11	Average							428

	Description	(A) Actual Balance 12/31/2001	(B) Actual 2002 Adds	(C) Actual 2002 Amort	(D) Actual Balance 12/31/2002	(E) Actual 2003 Adds	(F) Actual 2003 Amort	(G) Actual Balance 12/31/2003
	TOTAL MECO							
12	CWIP Equity Transition	496	-	(30)	466	-	(30)	436
13	SFAS 109 Flow-Through	261	-	(55)	207	-	(38)	168
14	Plant Transition	1,241	-	(111)	1,130	-	(103)	1,027
15	CWIP Equity	7,803	142	(356)	7,589	283	(372)	7,500
16	Federal ITC	(1,506)	-	167	(1,339)	-	165	(1,174)
17	Excess AccDep	(1,611)	-	366	(1,245)	-	366	(879)
18	Deficit AccDep	428	-	(39)	389	-	(39)	349
19	Deficit Deferred Tax	-	-	-	-	-	-	-
20	Excess Deferred Tax	-	-	-	-	-	-	-
21	Total	7,113	142	(58)	7,196	283	(53)	7,426
22	Average							7,311

* Amortization of Federal ITC was indavertently allocated to Molokai in detemining revenue requirements. The total amount should be allocated between Maui and Lanai only. The allocation will be revised at the next earliest opportunity.

(In Thousands)

	Description	(A) Actual Balance 12/31/2000	(B) Actual 2001 Adds	(C) Actual 2001 Amort	(D) Actual Balance 12/31/2001	
	MAUI					
1	CWIP Equity Transition	470	-	(27)	443	
2	SFAS 109 Flow-Through	288	-	(54)	234	
3	Plant Transition	1,211	-	(100)	1,110	
4	CWIP Equity	7,024	255	(301)	6,978	
5	Federal ITC	(1,496)	-	149	(1,346)	*
6	Excess AccDep	(1,768)	-	327	(1,440)	
7	Deficit AccDep	418	-	(35)	383	
8	Deficit Deferred Tax	(10)	-	10	-	
9	Excess Deferred Tax	(11)	-	11	-	
10	Total	6,127	255	(21)	6,361	
11	Average				6,244	

	Description	(A) Actual Balance 12/31/2000	(B) Actual 2001 Adds	(C) Actual 2001 Amort	(D) Actual Balance 12/31/2001	
	LANAI					
12	CWIP Equity Transition	25	-	(1)	23	
13	SFAS 109 Flow-Through	15	-	(3)	12	
14	Plant Transition	64	-	(5)	58	
15	CWIP Equity	370	13	(16)	368	
16	Federal ITC	(79)	-	8	(71)	*
17	Excess AccDep	(93)	-	17	(76)	
18	Deficit AccDep	22	-	(2)	20	
19	Deficit Deferred Tax	(1)	-	1	-	
20	Excess Deferred Tax	(1)	-	1	-	
21	Total	323	13	(1)	335	
22	Average				329	

* Amortization of Federal ITC was indavertently allocated to Molokai in detemining revenue requirements. The total amount should be allocated between Maui and Lanai only. The allocation will be revised at the next earliest opportunity.

(In Thousands)

	Description	(A) Actual Balance 12/31/2000	(B) Actual 2001 Adds	(C) Actual 2001 Amort	(D) Actual Balance 12/31/2001
	MOLOKAI				
1	CWIP Equity Transition	31	-	(2)	29
2	SFAS 109 Flow-Through	.19	-	(4)	15
3	Plant Transition	79	-	(7)	73
4	CWIP Equity	460	17	(20)	457
5	Federal ITC	(98)	-	10	(88) *
6	Excess AccDep	(116)	-	21	(94)
7	Deficit AccDep	27	-	(2)	25
8	Deficit Deferred Tax	(1)	-	1	-
9	Excess Deferred Tax	(1)	-	1	-
10	Total	402	17	(1)	417
11	Average				409

	Description	(A) Actual Balance 12/31/2000	(B) Actual 2001 Adds	(C) Actual 2001 Amort	(D) Actual Balance 12/31/2001
	TOTAL MECO				
12	CWIP Equity Transition	526	-	(30)	496
13	SFAS 109 Flow-Through	322	-	(61)	261
14	Plant Transition	1,354	-	(112)	1,241
15	CWIP Equity	7,855	285	(337)	7,803
16	Federal ITC	(1,673)	-	167	(1,506)
17	Excess AccDep	(1,977)	-	366	(1,611)
18	Deficit AccDep	467	-	(39)	428
19	Deficit Deferred Tax	(11)	-	11	-
20	Excess Deferred Tax	(12)	-	12	-
21	Total	6,852	285	(24)	7,113
22	Average				6,982

* Amortization of Federal ITC was indavertently allocated to Molokai in detemining revenue requirements. The total amount should be allocated between Maui and Lanai only. The allocation will be revised at the next earliest opportunity.

Maui Electric Company, Ltd.
Reconciliation of SFAS 109 Regulatory
Assets/Liabilities and Deferred Taxes

Dr/(Cr)

As of December 31, 2001

	Description	(A) MECO-1306 Regulatory Asset/Liab	(B) MECO-WP-1305 Fed Def Tax	(C) State Def Tax	(D) Other Adjust	(E) Difference	Note
1	CWIP Equity Transition	495,701	(419,071)	(76,630)		-	
2	SFAS 109 Flow-Thru	261,113	(220,748)	(40,365)		-	
3	Plant Transition	1,241,349	(1,049,449)	(191,899)		1	
4	CWIP Equity	7,802,710	(6,596,494)	(1,206,216)		-	
5	Federal ITC	(1,505,646)	1,272,889	232,757		-	(b)
6	Excess AccDep	(1,610,649)	529,819	96,881		(983,949)	(a)
7	Deficit AccDep	428,021	(140,796)	(25,746)		261,479	(a)
8	Deficit Deferred Taxes	-	-	-		-	(a)
9	Excess Deferred Taxes	-	-	-		-	(a)
10	Total	7,112,599	(6,623,850)	(1,211,218)	-	(722,469)	

As of December 31, 2002

	Description	(A) Regulatory Asset/Liab	(B) Fed Def Tax	(C) State Def Tax	(D) Other Adjust	(E) Difference	Note
11	CWIP Equity Transition	465,637	(393,654)	(71,983)		-	
12	SFAS 109 Flow-Thru	206,558	(174,626)	(31,932)		-	
13	Plant Transition	1,129,999	(955,314)	(174,686)		(1)	
14	CWIP Equity	7,588,902	(6,415,739)	(1,173,163)		-	
15	Federal ITC	(1,338,532)	1,131,609	206,923		-	(b)
16	Excess AccDep	(1,244,785)	409,469	74,874		(760,442)	(a)
17	Deficit AccDep	388,545	(127,810)	(23,372)		237,363	(a)
18	Deficit Deferred Taxes	-	-	-		-	(a)
19	Excess Deferred Taxes	-	-	-		-	(a)
20	Total	7,196,324	(6,526,065)	(1,193,339)	-	(523,080)	

(a) represents excess/deficit deferred tax balance previously included in the accum def tax balance

(b) the regulatory liability for federal ITC is being amortized over the same period as the related ITC

Maui Electric Company, Ltd.
Reconciliation of SFAS 109 Regulatory
Assets/Liabilities and Deferred Taxes

Dr/(Cr)

As of December 31, 2003		(A)	(B)	(C)	(D)	(E)	
		MECO-1306	MECO-WP-1305				
	Description	Regulatory Asset/Liab	Fed Def Tax	State Def Tax	Other Adjust	Difference	Note
1	CWIP Equity Transition	435,501	(368,177)	(67,324)		-	
2	SFAS 109 Flow-Thru	168,119	(142,130)	(25,990)		(1)	
3	Plant Transition	1,026,628	(867,923)	(158,706)		(1)	
4	CWIP Equity	7,499,838	(6,340,442)	(1,159,395)		1	
5	Federal ITC	(1,173,950)	992,469	181,480		(1)	(b)
6	Excess AccDep	(878,921)	289,119	52,867		(536,935)	(a)
7	Deficit AccDep	349,069	(114,824)	(20,998)		213,247	(a)
8	Deficit Deferred Taxes	0	-	-		-	(a)
9	Excess Deferred Taxes	0	-	-		-	(a)
10	Total	7,426,284	(6,551,908)	(1,198,066)	-	(323,690)	

As of December 31, 2004		(A)	(B)	(C)	(D)	(E)	
	Description	Regulatory Asset/Liab	Fed Def Tax	State Def Tax	Other Adjust	Difference	Note
11	CWIP Equity Transition	404,369	(341,858)	(62,511)		-	
12	SFAS 109 Flow-Thru	130,528	(110,350)	(20,178)		-	
13	Plant Transition	924,184	(781,315)	(142,869)		-	
14	CWIP Equity	7,359,915	(6,222,150)	(1,137,765)		-	
15	Federal ITC	(1,014,476)	857,649	156,827		-	(b)
16	Excess AccDep	(513,057)	168,769	30,861		(313,427)	(a)
17	Deficit AccDep	309,441	(101,790)	(18,613)		189,038	(a)
18	Deficit Deferred Taxes	0	-	-		-	(a)
19	Excess Deferred Taxes	0	-	-		-	(a)
20	Total	7,600,904	(6,531,045)	(1,194,248)	-	(124,389)	

(a) represents excess/deficit deferred tax balance previously included in the accum def tax balance

(b) the regulatory liability for federal ITC is being amortized over the same period as the related ITC

Maui Electric Company, Ltd.
Reconciliation of SFAS 109 Regulatory
Assets/Liabilities and Deferred Taxes

Dr/(Cr)

As of December 31, 2005

		(A)	(B)	(C)	(D)	(E)	
	Description	Regulatory Asset/Liab	Fed Def Tax	State Def Tax	Other Adjust	Difference	Note
1	CWIP Equity Transition	373,165	(315,477)	(57,687)		1	
2	SFAS 109 Flow-Thru	93,843	(79,336)	(14,507)		-	
3	Plant Transition	821,906	(694,848)	(127,058)		-	
4	CWIP Equity	7,522,961	(6,359,991)	(1,162,970)		-	
5	Federal ITC	(857,859)	725,243	132,616		-	(b)
6	Excess AccDep	(147,193)	48,419	8,854		(89,920)	(a)
7	Deficit AccDep	269,965	(88,804)	(16,238)		164,923	(a)
8	Deficit Deferred Taxes	(64,056)	21,071	3,853		(39,132)	(a)
9	Excess Deferred Taxes	5,835	(1,920)	(351)		3,564	(a)
10	Total	8,018,567	(6,745,643)	(1,233,488)	-	39,436	

As of December 31, 2006

		(A)	(B)	(C)	(D)	(E)	
	Description	Regulatory Asset/Liab	Fed Def Tax	State Def Tax	Other Adjust	Difference	Note
11	CWIP Equity Transition	343,029	(290,000)	(53,029)		-	
12	SFAS 109 Flow-Thru	60,910	(51,494)	(9,416)		-	
13	Plant Transition	726,120	(613,869)	(112,249)		2	
14	CWIP Equity	8,417,934	(7,116,610)	(1,301,323)		1	
15	Federal ITC	(715,047)	604,509	110,539		1	(b)
16	Excess AccDep	0	-	-		-	(a)
17	Deficit AccDep	230,489	(75,818)	(13,864)		140,807	(a)
18	Deficit Deferred Taxes	(56,424)	18,560	3,394		(34,470)	(a)
19	Excess Deferred Taxes	2,918	(960)	(176)		1,782	(a)
20	Total	9,009,929	(7,525,682)	(1,376,124)	-	108,123	

(a) represents excess/deficit deferred tax balance previously included in the accum def tax balance

(b) the regulatory liability for federal ITC is being amortized over the same period as the related ITC

Maui Electric Company, Ltd.
Reconciliation of SFAS 109 Regulatory
Assets/Liabilities and Deferred Taxes

Dr/(Cr)

As of December 31, 2007		(A)	(B)	(C)	(D)	(E)	
		MECO-1306	MECO-WP-1305				
	Description	Regulatory Asset/Liab	Fed Def Tax	State Def Tax	Other Adjust	Difference	Note
1	CWIP Equity Transition	315,455	(266,689)	(48,766)		-	
2	SFAS 109 Flow-Thru	32,148	(23,652)	(4,325)		4,171	(c)
3	Plant Transition	629,778	(532,726)	(97,411)		(359)	(c)
4	CWIP Equity	8,285,549	(7,013,104)	(1,282,396)		(9,951)	(c)
5	Federal ITC	(578,720)	489,257	89,464		1	(b)
6	Excess AccDep	-	-	-		-	(a)
7	Deficit AccDep	191,013	(62,832)	(11,490)		116,691	(a)
8	Deficit Deferred Taxes	(48,790)	16,049	2,935		(29,806)	(a)
9	Excess Deferred Taxes	-	-	-		-	(a)
10	Total	8,826,433	(7,393,697)	(1,351,989)	-	80,747	

(a) represents excess/deficit deferred tax balance previously included in the accum def tax balance

(b) the regulatory liability for federal ITC is being amortized over the same period as the related ITC

(c) Balances should be equal and offsetting. Amounts will be revised at the next earliest opportunity.

TESTIMONY OF
ANNABEL ARASE

UTILITY PLANT SUPERVISOR
ACCOUNTING DEPARTMENT
MAUI ELECTRIC COMPANY, LIMITED

Subject: Plant Additions
Plant Retirements
Property Held for Future Use
Contributions in Aid of Construction
Customer Advances

INTRODUCTION

Q. Please state your name and business address.

A. My name is Annabel Arase and my business address is 210 West Kamehameha Avenue, Kahului, Hawaii.

Q. By whom are you employed and in what capacity?

A. I am employed by Maui Electric Company, Limited ("MECO" or "Company") as the Utility Plant Supervisor in the Accounting Department.

Q. Please summarize your educational background and professional experience that relate to your testimony in this proceeding.

A. My educational background and experience are listed on MECO-1400.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to cover the following areas for the 2007 test year rate case for MECO.

1) Plant Additions,
2) Plant Retirements,
3) Property Held for Future Use,
4) Contributions in Aid of Construction, and
5) Customer Advances.

PLANT ADDITIONS

Q. What are plant additions?

A. Plant additions for a particular year represent the total cost of capital projects that are completed and placed in utility service during that year. A plant addition occurs when the costs for a capital project are transferred from the construction-work-in-progress to the utility plant-in-service account. The total capital expenditures incurred for a project are all included as part of the plant addition amount when the facility is completed and placed in service.

Q. What is the Company's estimate of plant additions during test year 2007?

A. As shown in MECO-1401, the Company's estimate of plant additions for 2007 is approximately $32,984,000 for Maui (line 2, column B), $417,000 for Lanai (line 2, column C), and $474,000 for Molokai (line 2, column D), for a total amount of approximately $33,875,000 (line 2, column E). See MECO-WP-1401B for a breakdown of the above amounts by project number and by island. These project number amounts are similarly broken down further into specific project costs in MECO-WP-1401C (which includes the straggling costs reflected in MECO-WP-1401D) and program expenditures in MECO-WP-1401E, as further discussed below.

Q. How are plant additions used in this rate case?

A. The plant addition amounts are utilized to determine the plant in service at the beginning of test year 2007 (i.e., as of December 31, 2006) and at the end of test year 2007 (i.e., as of December 31, 2007).

Q. Please explain in more detail.

A. The plant in service at the beginning of test year 2007 (i.e., as of December 31, 2006) is determined by adding the plant in service at the beginning of 2006 to the plant additions placed in service during 2006. The plant in service at the end of test year 2007 (i.e., as of December 31, 2007) is then determined by adding to this amount the plant additions that are planned to be placed in service during 2007.

Q. What is the Company's estimate of plant additions for 2006?

A. As shown in MECO-1401, the Company's estimate of plant additions for 2006 is approximately $89,434,000 for Maui (line 1, column B), $43,000 for Lanai (line 1, column C), and $53,000 for Molokai (line 1, column D), for a total amount of approximately $89,529,000 (line 1, column E). See MECO-WP-1401A for a breakdown of the above amounts by project number and by island. These project number amounts are then further broken down into specific project costs in MECO-WP-1401C (which includes the straggling costs reflected in MECO-WP-1401D) and program expenditures (formerly called blanket projects) in MECO-WP-1401E, as further discussed below.

Q. How were the estimates for plant additions in 2006 developed?

A. The plant additions for 2006 were estimated by adding the following three components:

1) for each specific project placed in service or forecasted to be placed in service in 2006, the sum of expenditures incurred and/or estimated to be incurred until the specific project is/was placed in service;
2) an estimate for straggling costs incurred or to be incurred in 2006 subsequent to the in service date, and
3) estimated program (formerly called blanket projects) expenditures for 2006.

Q. How were the estimates for plant additions for test year 2007 developed?

A. The plant additions estimate for 2007 was calculated in a similar manner, by adding:

1) for each specific project forecasted to be placed in service in 2007, the sum of any expenditures incurred to date on that project and estimated until the specific project is placed in service;
2) an estimate for straggling costs to be incurred in 2007 subsequent to the in service date, and
3) estimated program (formerly called blanket projects) expenditures for 2007.

Q. What is a specific project?

A. A specific project is a capital project that has an estimated total project cost greater than $20,000. Once identified as a specific project, the project is then identified with a specific project title and an estimated total expenditure amount so that it can be budgeted as a line item in the capital budget.

Q. How is the estimated total project cost (or plant addition amount) for a specific project determined?

A. The estimated total project cost (or plant addition amount) for a specific project consists of the sum of the cost of labor, materials, engineering, overheads and Allowance for Funds Used During Construction ("AFUDC") required to complete the specific project and place it in service.

Q. What are straggling costs?

A. Straggling costs are costs that are incurred on a capital project after it has already been placed in service, but which are prudently incurred and should be included as a capital budget item. Examples of straggling costs include, delayed billings from outside contractors for services already performed, monitoring expenses and the respective project manager's time in reviewing their projects to ensure proper closing and accounting of costs.

Q. What are program (formerly called blanket projects) expenditures?

A. Program (i.e., blanket) expenditures are capital projects that are too low in cost and/or too short in duration to warrant a specific project title or a separate line item in the capital project. Items in the program expenditure category generally run under $20,000 in total cost and/or require less than 30 days to construct.

Q. What types of expenditures are usually included as program (blanket) expenditures?

A. Program expenditures generally consist of, among other things, service drops, line extensions, installations or changeouts of meters and/or line transformers, vehicles, tools and equipment, and office furniture and equipment.

Q. How were the estimates for specific projects developed?

A. The Company's planners continually study the entire electrical system on the islands of Maui, Lanai and Molokai to forecast the need for additional electric facilities or modifications to existing facilities (such as upgrades of obsolete equipment or replacement of equipment that is no longer economical to maintain) to ensure the continued safe, reliable and efficient operation of each island's respective system. Based on factors such as load growth forecasts, the condition of existing facilities, new customer requests, and governmental regulations, the planners, in conjunction with the Company's designers and others responsible for building, operating, and maintaining the system, develop the specific projects or modifications that are needed to satisfy the expected needs. Outside consultants may be hired to assist in determining the best solutions or to assist with the design of a specific project.

Once a specific project has been identified, a project scope, timeline, estimate of required labor and resources, and resulting cost estimates are then prepared. Once completed, it is then provided to the Company's management personnel for their review and approval.

Once or if approved, the project manager or managers assigned to a specific project performs periodic reviews of the project and updates their cost estimates as appropriate to reflect new or updated information that results in the need to change the timeline, extent of labor and resources required and/or scope of the project.

Q. What are the estimates for specific project plant additions for 2006 and test year 2007?

A. The Company's estimate of plant additions attributable to specific projects, which includes straggling costs, completed and/or to be completed in 2006 and test year 2007 are approximately $80,934,000 and $24,411,000, respectively, as shown on MECO-WP-1401C (page 4), line 176, columns A and B.

Q. How were the estimates for straggling costs developed for purposes of this proceeding?

A. For 2006, the estimate for straggling costs are based on actual recorded costs through June 30, 2006 and by review of the remaining straggling costs for capital projects estimated for the remainder of 2006, as updated by the respective project managers. For 2007, the estimate for straggling costs was determined by reviewing the monthly projected expenditures for 2007 and plant additions date for each specific project to be added to plant in the 2007 test year, and then identifying the corresponding straggling costs for those projects. In general, the project managers identify in their estimates the straggling costs, which are costs not including AFUDC that are incurred subsequent to the in-service date of a specific plant addition.

Q. What are the estimates for plant additions attributable to straggling costs for 2006 and test year 2007?

A. The Company's estimate of plant additions attributable to straggling costs in 2006 and test year 2007 are approximately $1,017,000 and $411,000, respectively, as shown on MECO-WP-1401D, line 45, columns A and B, respectively.

Q. How were the estimates for program (blanket) expenditures developed for 2006?

A. For 2006, the estimates for program (blanket) expenditures were based on recorded amounts through June 30, 2006 plus an estimate of planned expenditures for the remainder of the year (i.e., through December 31, 2006). For each program expenditure, an assigned project manager is responsible for reviewing the recorded totals and then forecasting the expenditures for the remainder of the year based on recorded information and the outlook for the remainder of the year.

Q. How were the estimates for program (blanket) expenditures developed for test year 2007?

A. For test year 2007, the Company reviewed historical expenditures from 2001-2005, and the responsible project manager forecasted the expenditures for 2007 based on the recorded five-year average, adjusted for 2006 amounts and other current trends that would impact the respective program project.

Q. What are the estimated plant additions attributable to program (blanket) projects in 2006 and test year 2007?

A. The Company's estimate of program projects in 2006 and test year 2007 are approximately $8,595,000 and $9,464,000, respectively, as shown on MECO-WP-1401E (page 2), line 52, columns A and B.

Q. How is the Company's total capital expenditures estimate determined once specific projects are identified and their associated scope, timeline, and cost estimates are developed?

A. Once individual projects are identified and their scope, timeline, and cost estimates developed, the following process is generally followed in developing the Company's capital expenditures estimate:

1) Managers and staff from each department meet to review and rank, to the degree possible, their proposed projects to determine which projects should move forward in the budget process.

2) Projects are reviewed by the responsible process areas to determine which projects should be considered for inclusion in the upcoming five-year capital budget.

3) The lists of proposed projects for each process area are compiled and presented to the Capital Budget Committee ("CBC").

4) The CBC reviews the proposed projects from a Company-wide perspective and determines those projects that will be included in (or excluded from) the upcoming five-year capital budget.

5) The project manager or responsible party receives the approved project list and builds/refines/updates the detailed budget estimate.

During the detailed budgeting process, resource leveling reports are generated at several key points in the process to allow those providing resources an opportunity to view the demands, in terms of labor hours, placed on their respective resources. If necessary, adjustments are then made to level the demand placed on a specific resource class. This generally results in a more realistic capital budget.

6) To ensure the completeness of the Company's final capital budget, consideration is given to any projects that were deferred from consideration or that were created during the period between the initial review period and when the detailed budgeting was built/refined.

7) The proposed capital budget is then reviewed at Company officer briefings to further determine those projects that will be included in (or excluded from) the final budget for the upcoming five year period.

8) Subsequently, the five-year capital budget is presented to the Company's Board of Directors for its review and approval.

The plant addition estimates are an outcome of the process that develops the Company's capital expenditures estimate.

Q. How are joint pole contributions treated for 2006 and test year 2007 in determining the capital expenditure and/or plant addition amounts?

A. Estimated capital joint pole contributions are included as a credit (reduction) in a program's capital expenditure and plant addition estimates.

Q. Were any adjustments made to the above plant addition estimates to reflect possible delays in project schedules?

A. No. The Company's forecasted plant additions are reasonable without the need to make any adjustments for possible delays.

Q. Please explain why the Company's forecasted plant additions are reasonable.

A. Even though it is anticipated that some of the planned projects for 2006 and test year 2007 may not be placed in-service as scheduled and will instead be placed in service later than anticipated, there are other projects that are not currently included in these estimates that will either (1) be completed earlier than projected, or (2) be identified as a need after the budget is finalized and completed and placed in service in 2006 or 2007. In support of this, see MECO-1402 for a comparison from 2001 through 2005 of the budgeted versus recorded plant addition amounts. As noted therein, the annual percentage differences between recorded and forecasted total plant additions ranged from (20%) to 48%, or on average, a 17% difference in total over the five-year period. What this demonstrates is that the actual recorded total plant additions on average are higher than the Company's forecasted plant additions developed through its budget process. As such, the Company believes that the 2006 and test year 2007 plant additions estimates are reasonable without the need to make any adjustments based on possibly unanticipated construction delays that may occur.

Q. Please explain why the 2006 and test year 2007 plant additions estimates are higher than the 2001-2005 average?

A. The 2006 plant additions estimate is higher than the 2001-2005 average due to the addition of project number M3141001, Maalaea Power Plant Unit 18 for $61,725,000 and higher than average in-kind CIAC estimate (Project M8020000).

For the 2007 test year, the plant additions estimate is higher than the 5-year average also due to higher than average in-kind CIAC. In addition, as a result of increasing load demand, there is a need for additional transmission and distribution facilities as well as modifications to existing facilities that is higher than the 5-year average.

Q. Does the Commission have the opportunity to review any of the specific projects that are expected to be added to plant in service? Please explain.

A. Yes. The Company is required by Paragraph 2.3.(g)(2) of General Order No. 7, Standards for Electric Utility Service ("General Order No. 7"), as amended by In re Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited, Docket No. 03-0257, Decision and Order No. 21002 (May 27, 2004), to submit all proposed capital expenditures for any single project related to plant replacement, expansion or modernization in excess of $2,500,000, excluding customer contributions, to the Commission for review at least 60 days prior to commencement of construction or commitment for expenditure, whichever is earlier.

Q. Which capital projects costing more than $2,500,000 each have been and/or are expected to be completed in 2006 and included in plant additions?

A. Project number M3141001, Maalaea Power Plant Unit 18 ("Maalaea Unit 18"), was placed in-service in October 2006 with an estimated total project cost of approximately $61,725,000. This estimate was provided by the project manager based on actual costs thru June 2006 and projected costs through December 2006. See MECO-WP-1401A (page 1), line 1, columns A and B.

Q. Which capital projects costing more than $2,500,000 each are expected to be completed in test year 2007 and included in plant additions?

A. There are no projects costing more than $2,500,000 that are forecasted to be placed in service and included in plant additions in test year 2007. However, straggling costs from Maalaea Unit 18 have been and are being incurred after it was placed in-service in October 2006. It is expected that, of the approximately $61,725,000 total project cost to be placed into plant additions in 2006, approximately $695,000 of this amount will consist of straggling costs. See MECO-WP-1401D, line 40, column A. In addition, approximately $308,000 in straggling costs is anticipated during 2007 relating to Maalaea Unit 18. See MECO-WP-1401B (page 1, line 1, columns A and B) and MECO-WP-1401D (line 40, column B).

Q. Please describe project number M3141001, Maalaea Unit 18.

A. As discussed in Mr. Mike Ribao's testimony in T-5, Maalaea Unit 18 is Phase III of the Maalaea Dual Train Combined Cycle Number Two project, which involves the purchase and installation of an 18 megawatt ("MW") steam turbine generator, two heat recovery steam generators, one air cooled condenser and auxiliary equipment. Maalaea Unit 18 (Phase III) will meet the growing load demand on the island of Maui and improve the Company's overall reliability of its generation system.

Q. Has the Company received approval from the Commission for this project?

A. Yes. Maalaea Unit 18 (Phase III) was approved as part of the Maalaea Dual Train Combined Cycle Number Two project in Decision and Order No. 13730, filed on January 11, 1995, in Docket No. 7744. Phase I (M17) and Phase II (M19) was placed into commercial operation in December 1998 and September 2000, respectively.

As noted above, M18 was placed in-service in October 2006 and the increase in cost of the project has been explained in the quarterly project status report as of June 30, 2006 submitted to the Commission. An extension to file the Interim Accounting Report, with an explanation of any deviation of ten percent (10%) or more in the project's cost from that estimated in the Company's Application in Docket No. 7744, was granted by the Commission and the Company plans to file the report with the Commission no later than February 26, 2007. The current anticipated total project cost is $64.8 million, which is $2.8 million higher than the forecasted rate case plant addition total for 2006 and 2007 test year. The primary reasons for the cost increase are due to additional start up costs including material, labor and outside services and additional costs incurred as a result of the delayed project completion date from September to October 2006. The Company will update the M18 project costs in its test year estimates at the first available opportunity.

Q. Since the 1999 test year rate case, have any of the other phases of this project been placed in service?

A. Yes. As stated above, Maalaea Unit 19 (Phase II) was placed in service in September 2000 at a total project cost of $24,627,561 and will be included in the revenue requirements of this docket (Docket No. 2006-0387).

Q. Which projects are estimated to cost more than $1,000,000 but less than $2,500,000 and are expected to be completed in 2006?

A. As shown on MECO-1403 (page 1), there are two projects: (1) project number M0000012, Waiinu Sub 36 Unit Substation/69kV Breaker Addition, and (2) project number M0000730, Substation 36 Unit 3 Transformer Addition, estimated to cost approximately $2,033,000 (line 1, column C) and $1,065,000 (line 2, column C), respectively.

Q. Please describe these two projects.

A. Project Number M0000012, Waiinu Sub 36 Unit Substation/69kV Breaker Addition: This project involves the replacement and upgrade of the transformer unit and the addition of three 69 kilovolt ("kV") breakers and related equipment at the Waiinu Substation 36. The transformer upgrade will improve system reliability in the area on the island of Maui.

Project Number M0000730, Substation 36 Unit 3 Transformer Addition: Also at the Waiinu Substation 36, this project involves the installation of a new distribution unit transformer, switchgear, and related equipment, and construction of an overhead distribution line to interconnect to the existing distribution system to accommodate the current and continuing growth in the Wailuku area on the island of Maui.

Q. Which projects are estimated to cost more than $1,000,000, but less than $2,500,000 and are expected to be completed in test year 2007?

A. As shown on MECO-1403 (page 2), there are two projects: (1) project number M0000697, 69kV Waikapu Relocation, and (2) project number M0000809, Kihei Sub 35 – Transformer/Switchgear #4 Addition, estimated to cost approximately $1,573,000 (line 1, column C) and $1,148,000 (line 2, column C), respectively.

Q. Please describe these two projects.

A. Project Number M0000697, 69kV Waikapu Relocation: This project generally involves the relocation at the request of a private developer of a portion of the existing Waikapu 69 kV transmission line (which generally serves the Waikapu and Wailuku areas on Maui) above the surface of the ground. On June 13, 2006, the Company filed an Application in Docket No. 2006-0157 requesting that the Commission: (1) conduct a public hearing, pursuant to Hawaii Revised Statutes ("HRS") Section 269-27.5, regarding its proposal to relocate the existing 69kV transmission line through a residential area; and (2) determine, pursuant to HRS Section 269-27.6(a), that the Company's proposal to relocate the 69kV transmission line above the surface of the ground is appropriate. A public hearing on this project was held by the Commission on August 11, 2006 on the island of Maui. On October 30, 2006, the Commission issued Decision and Order No. 22991 approving the overhead construction of the 69kV transmission line.

Project Number M0000809, Kihei Sub 35 – Transformer/Switchgear #4 Addition: This project involves the installation of a new transformer, switchgear, and associated electrical equipment at the Kihei Substation 35 in order to accommodate the current and continuing development in the Kihei area on the island of Maui.

Q. Does the Commission have the opportunity to review any of the specific projects that are estimated to cost more than $1,000,000 but less than $2,500,000? Please explain.

A. Yes. The Company is required by Paragraph 2.3.(g)(2) of General Order No. 7, as amended by In re Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited, Docket No. 03-0257, Decision and Order No. 21002 (May 27, 2004), to itemize the actual costs incurred for each completed project with a total cost between $1 million to under $2.5 million, provide an explanation of any deviations of plus or minus fifteen percent (15%) from the budgeted cost, and provide a general discussion of the reasons causing the variance. The report must be filed by May 31st of each calendar year for the preceding year. The most recent report was filed with the Commission on May 31, 2006.

MAUI DIVISION PLANT ADDITIONS

Q. Of the above projects (i.e., projects greater than $1,000,000), which of these projects are for the Maui Division/island of Maui in 2006?

A. Project number M3141001, Maalaea Unit 18, project number M0000012, Waiinu Sub 36 Unit Substation/69kV Breaker Addition, and project number M0000730, Substation 36 Unit 3 Transformer Addition, at an estimated cost of approximately $61,725,000, $2,033,000 and $1,065,000, respectively, as mentioned above.

Q. Of the above projects (i.e., projects greater than $1,000,000), which of these projects are for the Maui Division/island of Maui in 2007?

A. Project number M0000697, 69kV Waikapu Relocation, and project number M0000809, Kihei Sub 35 – Transformer/Switchgear #4 Addition, at an estimated cost of approximately $1,573,000 and $1,148,000, respectively, as mentioned above.

LANAI DIVISION PLANT ADDITIONS

Q. Of the above projects (i.e., projects greater than $1,000,000), which of these projects are for the Lanai Division/island of Lanai in 2006?

A. None. The Company does not anticipate any major plant additions for the Lanai Division in 2006.

Q. Of the above projects (i.e., projects greater than $1,000,000), which of these projects are for the Lanai Division/island of Lanai in 2007?

A. None. The Company does not anticipate any major plant additions for the Lanai Division in 2007.

MOLOKAI DIVISION PLANT ADDITIONS

Q. Of the above projects (i.e., projects greater than $1,000,000), which of these projects are for the Molokai Division/island of Molokai in 2006?

A. None. The Company does not anticipate any major plant additions for the Molokai Division in 2006.

Q. Of the above projects (i.e., projects greater than $1,000,000), which of these projects are for the Molokai Division/island of Molokai in 2007?

A. None. The Company does not anticipate any major plant additions for the Molokai Division in 2007.

PLANT RETIREMENTS

Q. What are plant retirements?

A. Plant retirements include the costs of facilities that were used for utility purposes in the past, but which have been removed or retired from service and are no longer used or useful for utility purposes.

Q. What is the Company's estimate of plant retirements for 2006?

A. As shown on MECO-1404 (page 1), the estimated amount of plant retirements for 2006 are approximately $1,022,000 for Maui (line 5, column A), $6,000 for Lanai (line 5, column B), and $11,000 for Molokai (line 5, column C), for a total amount of approximately $1,040,000 (line 5, column D).

Q. What is the Company's estimate of plant retirements for test year 2007?

A. As shown on MECO-1404 (page 2), the estimated amount of plant retirements for test year 2007 are approximately $1,018,000 for Maui (line 5, column A), $6,000 for Lanai (line 5, column B), and $44,000 for Molokai (line 5, column C), for a total amount of approximately $1,068,000 (line 5, column D).

Q. How were the plant retirements for 2006 and test year 2007 estimated?

A. For functional categories, plant retirements were estimated for 2006 and the 2007 test year by examining the historical ratio of actual plant retirements per functional group to plant balances for the previous five years (2001-2005). The Company then calculated a five-year simple average ratio to determine the estimated plant retirements for 2006 and the 2007 test year, with the exception of vehicle retirements. Vehicle retirements were determined separately based on the actual cost of the vehicle designated for retirement in the corresponding years. See MECO-WP-1404A and MECO-WP-1404B.

Q. How does the 2006 and 2007 test year estimates of plant retirements compare with amounts recorded in preceding years?

A. The 2006 and 2007 test year estimates of plant retirements are equal to the 5-year average adjusted for the forecasted vehicle retirements as shown on MECO-WP-1404A.

PROPERTY HELD FOR FUTURE USE

Q. What is property held for future use?

A. Property held for future use is property that is not currently used and useful for utility operations, but is being owned and held by the Company for its future use in the provision of utility services under a definite plan.

Q. Does the Company have any property that is being held for future use? If so, please explain.

A. Yes, there is one property. The Company owns a parcel of land for the future Waena Power Plant. The Company acquired approximately 67 acres of land and related easements in central Maui in December 1996 at a cost of $1.9 million, and has since incurred rezoning costs of approximately $0.7 million, for a total cost of approximately $2.633 million. See MECO-1405 (page 2), line 1, column E.

Q. Did the Commission approve the Company's purchase of this property?

A. Yes. The Commission approved the purchase of this property in Decision and Order No. 14675, filed on May 10, 1996, in Docket No. 96-0039.

Q. What is the expected in-service date of the Waena Power Plant?

A. The Company currently estimates that the Waena Power Plant will be constructed and placed in-service in the year 2011. See page 2 of MECO-1405 (line 1, column D).

Q. What are the Company's estimates of property held for future use for 2006 and test year 2007 as a result of this property?

A. The Company's estimated balance of its property held for future use for both 2006 and test year 2007 is the $2,633,000 amount for the future Waena Power Plant site, as shown on page 1 of MECO-1405 (lines 3 and 5, column B).

Q. Does the Company plan to add or subtract from its property held for future use amounts for either 2006 or test year 2007?

A. No. The Company anticipates that no properties will be added to or subtracted from property held for future use in 2006 and test year 2007.

Q. What is the Company's position for recovering its costs incurred for the subject property as property held for future use?

A. Even though the power plant is not planned to be constructed and placed in-service on the subject property until 2011, the Company has demonstrated that the acquisition was prudent and required for future use as part of its approval in Docket No. 96-0039 and that it is reasonable to include its costs associated with the subject property as property held for future use.

In addition, since the acquisition of the property, the Company has incurred approximately $717,000 in rezoning costs for the purpose of preparing the land for its intended use. The lack of appropriate zoning would effectively render the property useless for its intended purpose as a power generating site.

Further, in the 2007 test year, project M0000817, Waena Secure Staging Area, is forecasted to be added to plant at a total project cost of $140,286, as shown on MECO-WP-1401B (page 2, line 71, columns A and B). This project involves establishing a secured area on the subject property for material and equipment storage to relieve the congestion at the Kahului Baseyard.

Inclusion of the Waena Power Plant Site in property held for future use is also consistent with the Commission's Decision and Orders No. 16922 for MECO's last rate case in Docket No. 97-0346.

CONTRIBUTIONS IN AID OF CONSTRUCTION ("CIAC")

Q. What is CIAC?

A. CIAC, or contribution in aid of construction, is defined in Rule No. 1 of the Company's tariff as "money, property, or services contributed to the Company for construction which is not subject to refund or reimbursement in whole or in part." These types of contributions are non-refundable and generally are required when a customer requests services and/or facilities that are acceptable to the Company, but which involve or require additions beyond the standard facilities that the Company would normally install. For example, when a customer requests an underground installation, the Company collects a non-refundable contribution from the customer equal to the difference between the cost of the underground facility and the lower estimated cost of an equivalent overhead facility. The amount collected is classified as cash CIAC.

Q. What are in-kind contributions?

A. In-kind contributions (aka, in-kind CIAC) are non-cash contributions such as duct line infrastructure built by a subdivision developer or similar customer who later dedicates or turns over ownership of the facilities to the Company.

Q. How is the value of in-kind contributions determined?

A. The value of in-kind contributions is determined based on the cost estimates to construct the in-kind contribution, such as the duct line infrastructure. In addition, the Company periodically reviews the base year unit costs for in-kind contribution infrastructures to ensure that they are reasonable, that they reflect current construction costs, and that they are also adjusted based on the Handy Whitman Index Utility Guide for the Pacific Region.

Q. What is the Company's estimated cash CIAC receipts for 2006?

A. As shown on MECO-1406 (page 1), the estimated cash CIAC receipts for 2006 are approximately $2,856,000 for Maui (line 1, column A), $37,000 for Lanai (line 1, column B), and $20,000 for Molokai (line 1, column C), for a total cash CIAC receipts amount of approximately $2,913,000 (line 1, column D).

Q. What is the Company's estimated cash CIAC receipts for the test year 2007?

A. As shown on MECO-1406 (page 2), the estimated cash CIAC receipts for the 2007 test year are approximately $1,915,000 for Maui (line 1, column A), $75,000 for Lanai (line 1, column B), and $328,000 for Molokai (line 1, column C), for a total cash CIAC receipts amount of approximately $2,318,000 (line 1, column D).

Q. How was the cash CIAC receipts amount estimated for 2006?

A. For 2006, the estimate is based on the recorded cash CIAC receipts through June 30, 2006 and then trended for the remainder of 2006 based on estimated remaining receipts for 2006, as shown on MECO-WP-1406A.

Q. How was the cash CIAC receipts amount estimated for test year 2007?

A. For the 2007 test year, the Company determined the percentage of CIAC received for the years 2001-2005 as compared to capital expenditures for those years related to construction projects for which the Company may receive CIAC (such as overhead and underground services and extensions). This percentage (41.6%) was then multiplied by the total estimated capital expenditures related to construction projects for which the Company may receive CIAC. The result represents the estimated test year 2007 cash CIAC amount (including transfers from Customer Advances) (aka Net Cash CIAC). See MECO-WP-1406C.

Q. Why are the estimates of cash CIAC receipts higher in 2006 than the 2007 test year estimate?

A. The estimated cash CIAC receipts for 2006 are higher than test year 2007 primarily because of the recorded cash CIAC amounts in 2006 of $490,435 and

$351,896 for the State of Hawaii Honoapiilani Highway Widening projects for Kaanapali and Maalaea, respectively.

Q. What is the estimated amount for transfers from customer advances to CIAC in 2006?

A. As shown in MECO-1406 (page 1), the estimated amount for transfers from customer advances to CIAC for 2006 is approximately $119,000 for Maui (line 2, column A), $51,000 for Lanai (line 2, column B), and $592,000 for Molokai (line 2, column C), for a total amount of approximately 762,000 (line 2, column D).

Q. What is the estimated amount for transfers from customer advances to CIAC in test year 2007?

A. As shown in MECO-1406 (page 2), the estimated amount for transfers from customer advances to CIAC for test year 2007 is approximately $212,000 for Maui (line 2, column A), $0 for Lanai (line 2, column B), and $108,000 for Molokai (line 2, column C), for a total amount of approximately $320,000 (line 2, column D). Transfers from customer advances are discussed further in the next section below entitled Customer Advances.

Q. What is the Company's estimate of in-kind CIAC for 2006 and test year 2007?

A. The estimated in-kind CIAC for 2006 is approximately $6,769,000 for 2006 and $6,931,000 for test year 2007, as shown on MECO-1406 (page 1, line 4, column D) and (page 2, line 4, column D), respectively. As noted in column A of MECO-1406, pages 1 and 2, these estimated in-kind CIAC amounts are for the Maui Division only.

Q. Why are the estimated in-kind CIAC amounts for the Maui Division only?

A. There are no in-kind CIAC amounts forecasted for the Lanai and Molokai Divisions in 2006 or test year 2007.

Q. How did the Company estimate the in-kind CIAC amount for 2006?

A. The in-kind CIAC estimate for 2006 are based on actual recorded in-kind CIAC through June 30, 2006 and by review of known specific projects with in-kind CIAC contributions, identifying those projects that are estimated to be recorded for the remainder of 2006, as updated by the respective project managers and MECO Senior Inspector, and quantifying their in-kind CIAC value. See MECO-WP-1406D.

Q. How did the Company estimate the in-kind CIAC amount for test year 2007?

A. The in-kind CIAC estimate for the test year 2007 was obtained by applying the "Growth rate based on July 2005 Sales & Peak Forecast Avg. No. of Customers" for 2007 of 1.024 to the 2006 in-kind CIAC estimate of $6,769,000. See MECO-WP-1406D.

Q. Why are the estimated in-kind CIAC higher for 2006 and test year 2007 than the 5-year average?

A. The estimated in-kind CIAC for 2006 and test year 2007 are higher than the 5-year average due to an increased number of subdivisions as well as the size and underground infrastructure requirements for these qualifying in-kind CIAC subdivision projects thus resulting in higher in-kind CIAC contributions.

CUSTOMER ADVANCES

Q. What are customer advances?

A. Customer advances are funds advanced by a customer for facilities provided by the Company. Rule No. 1 of the Company's Tariff defines Customer Advances as "The amount of money paid to the Company for construction which may be subject to refund in whole or in part." Similar to CIAC, the Company collects funds from the customer in exchange for facilities to be provided by the Company. However, customer advances differ from CIAC in that they are subject to refund in whole or in part under certain situations.

Generally, customer advances are required for:

1) requests for service that require new lines to be constructed for which the cost to construct the lines exceeds the Company's expected revenue from that customer for 60 months, and

2) the installation of electric meters in a newly built subdivision.

Q. What are the components of customer advances?

A. Customer advances consist of receipts of customer advances as offset/reduced by (1) refunds of customer advances, and (2) transfers of customer advances to CIAC.

Q. What are the estimated receipts of customer advances for 2006?

A. As shown on MECO-1407 (page 1), estimated receipts of customer advances for 2006 are approximately $1,120,000 for Maui (line 1, column A), $54,000 for Lanai (line 1, column B), and $47,000 for Molokai (line 1, column C), for a total amount of approximately $1,221,000 (line 1, column D).

Q. What are the estimated receipts of customer advances for the 2007 test year?

A. As shown on MECO-1407 (page 2), estimated receipts of customer advances for the 2007 test year are $1,198,000 for Maui (line 1, column A), $59,000 for Lanai (line 1, column B), and $50,000 for Molokai (line 1, column C), for a total amount of approximately $1,307,000 (line 1, column D).

Q. How did the Company estimate the customer advance receipts?

A. The Company compared the percentage of actual customer advances received for the years 2001-2005 to actual capital expenditures for those years related to construction projects for which the Company may receive customer advances. The resulting percentage (20.62%) was then multiplied by the total estimated capital expenditures related to construction projects for which the Company may receive customer advances for 2006 and test year 2007. The result represents the estimated 2006 and test year 2007 customer advance receipts as shown on MECO-WP-1407A and then carried forward to MECO-1407.

Q. What are customer advance refunds?

A. Customer advance refunds are made when permanent customers within the subdivision are connected to the lines based on the estimated revenues for sixty months from such permanent customers in the subdivision. The total amount to be refunded is limited to the amount of the advance made by the developer or subdivider. In addition, no refund will be made after five years from the date of the advance as stated in Rule No. 13 in the Company's tariff.

Q. What are the estimated customer advance refunds for 2006?

A. As shown on MECO-1407 (page 1), the Company's estimated customer advance refunds for 2006 are approximately $1,499,000 for Maui (line 2, column A), $187,000 for Lanai (line 2, column B), and $61,000 for Molokai (line 2, column C), for a total amount of approximately $1,747,000 (line 2, column D).

Q. What are the estimated Customer Advance refunds for the 2007 test year?

A. As shown in MECO-1407 (page 2), the Company's estimated Customer Advance refunds for the 2007 test year are approximately $587,000 for Maui (line 2, column A), $12,000 for Lanai (line 2, column B), and $3,000 for Molokai (line 2, column C), for a total amount of approximately $602,000 (line 2, column D).

Q. Why are the estimated customer advance refunds higher in 2006 than test year 2007?

A. The customer advance refunds are higher in 2006 than test year 2007 because the 2006 estimate is based on actual recorded refunds through June 30, 2006, which includes underground subdivisions with abnormally large advance balances that were eligible for refunds. This amount was then trended for the remaining year based on the historical five-year refund percentage average to the customer advance balances.

Q. How was the amount for 2007 test year customer advance refunds estimated?

A. The Company compared the percentage of actual customer advance refunds for the years 2001-2005 to actual customer advance balances for those years. The resulting percentage by island was then multiplied by the estimated 2006 customer advance balance for each island to arrive at the 2007 test year estimates as shown on MECO-WP-1407B.

Q. What are the estimated amounts for customer advance transfers to CIAC for 2006?

A. As shown on page 1 of MECO-1406 and MECO-1407, lines 2 and 3, respectively, the estimated amounts for the transfer from customer advance to CIAC for 2006 is approximately $119,000 for Maui, $51,000 for Lanai, and $592,000 for Molokai, for a total amount of approximately $762,000.

Q. What are the estimated amounts for customer advance transfers to CIAC for the 2007 test year?

A. As shown on page 2 of MECO-1406 and MECO-1407, lines 2 and 3, respectively, the estimated amounts for the transfer from customer advance to CIAC for test year 2007 is $212,000 for Maui, $0 for Lanai, and $108,000 for Molokai, for a total amount of approximately $320,000.

Q. Why are customer advances transferred to CIAC?

A. A customer advance amount is transferred to CIAC when the five-year refund period applicable to an advance has expired, at which time the amount of any remaining customer advance balance for a project that has not yet been refunded is transferred to CIAC.

Q.. How were the amounts for transfers to CIAC of customer advances estimated for 2006?

A. The estimated 2006 transfers to CIAC are based on actual recorded transfers through June 30, 2006 adjusted for additional transfers forecasted for the remainder of that year, which was forecasted by reviewing the customer advance balances that are expected to expire at year-end net of refunds. See MECO-WP-1406B.

Q. How were the amounts for transfers to CIAC of customer advances estimated for test year 2007?

A. The 2007 test year transfers to CIAC were obtained by reviewing the customer advance balances that are expected to expire in 2007 net of forecasted refunds, as shown on MECO-WP-1406B.

Q. Why is the estimated transfer to CIAC for Molokai higher in 2006 than test year 2007?

A. The estimated transfer to CIAC for Molokai is higher in 2006 than test year 2007 due primarily to expired advances for project Kalamaula Residential Lot Subdivision Unit 1 and West Hoolehua Farm Lots Phase 1 in the amounts of $381,388 and $80,870, respectively.

SUMMARY

Q. Please summarize your testimony.

A. The Company proposes that its plant additions estimate for 2006 and test year 2007 be based on the total cost of all projects estimated to be placed in service in 2006 and 2007, respectively. See MECO-1401.

The Company's estimate of plant additions for 2006 is $89,434,000 for Maui, $43,000 for Lanai, and $53,000 for Molokai, for a total 2006 plant addition amount of approximately $89,529,000. The Company's estimate of plant additions for test year 2007 is $32,984,000 for Maui, $417,000 for Lanai, and $474,000 for Molokai, for a total test year 2007 plant addition amount of approximately $33,875,000. See MECO-1401.

The estimated amounts of plant retirements for 2006 are $1,022,000 for Maui, $6,000 for Lanai, and $11,000 for Molokai, for a total estimated plant retirement amount for 2006 of approximately $1,040,000. The estimated amounts of plant retirements for test year 2007 are $1,018,000 for Maui, $6,000 for Lanai, and $44,000 for Molokai, for a total estimated plant retirement amount for test year 2007 of approximately $1,068,000. See MECO-1404.

The Company further proposes that its Waena Power Plant site be included in the test year 2007 balance of property held for future use, with a resulting balance of property held for future use of $2,633,000 for 2006 and test year 2007. See MECO-1405. The Company already owns the property, has shown that the acquisition was reasonable and prudent, and that the property is required for future use.

The estimated 2006 net cash CIAC including transfers from customer advances is $2,975,000 for Maui, $88,000 for Lanai, and $612,000 for Molokai, for a total net cash CIAC amount for 2006 of approximately $3,675,000. The test year 2007 net cash CIAC including transfers from customer advances is $2,127,000 for Maui, $75,000 for Lanai, and $436,000 for Molokai, for a total net cash CIAC amount for test year 2007 of approximately $2,638,000. The estimated total MECO 2006 and test year 2007 in-kind CIAC is $6,769,000 and $6,931,000, respectively. See MECO-1406.

The estimated amount for 2006 customer advance receipts is $1,120,000 for Maui, $54,000 for Lanai, and $47,000 for Molokai, for a total customer advance receipt amount for 2006 of approximately $1,221,000. The estimated test year 2007 amount for customer advance receipts is $1,198,000 for Maui, $59,000 for Lanai, and $50,000 for Molokai, for a total customer advance receipt amount for test year 2007 of approximately $1,307,000. See MECO-1407.

The estimated amount for 2006 customer advance refunds is $1,499,000 for Maui, $187,000 for Lanai, and $61,000 for Molokai, for a total customer advance refunds amount for 2006 of approximately $1,747,000. The estimated amount for test year 2007 customer advance refunds is $587,000 for Maui, $12,000 for Lanai, and $3,000 for Molokai, for a total customer advance refunds amount for test year 2007 of approximately $602,000. See MECO-1407.

The estimated 2006 amount for customer advance transfers to CIAC is $119,000 for Maui, $51,000 for Lanai, and $592,000 for Molokai, for a total customer advance transfers to CIAC amount for 2006 of approximately $762,000. The estimated test year 2007 amount for customer advance transfers to CIAC is $212,000 for Maui, none for Lanai, and $108,000 for Molokai, for a total customer advance transfers to CIAC amount for test year 2007 of approximately $320,000. See MECO-1406 and MECO-1407.

Q. What are your conclusions?

A. The Company's estimates for plant additions, plant retirements, property held for future use, CIAC and customer advances are just and reasonable for test year ratemaking purposes.

Q. Does this conclude your testimony?

A. Yes.

MAUI ELECTRIC COMPANY, LIMITED

ANNABEL ARASE

EDUCATIONAL BACKGROUND AND EXPERIENCE

Business Address:	Maui Electric Company, Limited 210 West Kamehameha Ave. Kahului, HI 96732
Current Position:	Utility Plant Supervisor (June, 2006 to current)
Years of Service:	3
Prior Positions at MECO:	Capital Budget Analyst 2005-2006 Tax and Property Accounting Analyst 2003-2005
Education:	University of Hawaii (Manoa) Bachelor of Business Administration-Accounting
Previous Rate Case Testimony:	None
Professional License:	Certified Public Accountant (not in public practice)

Maui Electric Company, Limited

2006 and 2007

PLANT ADDITIONS

($ Thousands)

	(A) Year	(B) Maui	(C) Lanai	(D) Molokai	(E) Total	(F) Reference
1	2006	89,434	43	53	89,529	MECO-WP-1401A
2	2007	32,984	417	474	33,875	MECO-WP-1401B

Sources
Specific Project Costs (including Straggling Costs): MECO-WP-1401C
Straggling Costs: MECO-WP-1401D
Program Expenditures: MECO-WP-1401E

Totals may not add due to rounding.

Maui Electric Company, Limited

2001 - 2005

PLANT ADDITIONS

($ Thousands)

	(A) Year	(B) Recorded	(C) Budget	(D) $ Difference	(E) % Difference
1	2001	22,513	28,140	-5,627	-20%
2	2002	22,442	16,336	6,106	37%
3	2003	35,969	24,352	11,617	48%
4	2004	26,224	22,732	3,493	15%
5	2005	24,398	21,009	3,389	16%
6	2001-2005	131,546	112,569	18,978	17%

Totals may not add due to rounding.

Maui Electric Company, Limited

2006

SPECIFIC PROJECTS OVER $1,000,000 AND LESS THAN $2,500,000
TO BE ADDED TO PLANT

($ Thousands)

	(A) Project No.	(B) Project Description	(C) Estimated Plant Additions	(D) Reference
1	M0000012	Waiinu Sub 36 Unit Substation/ 69 kV Breaker Addition	2,033	MECO-WP-1401A
2	M0000730	Substation 36 Unit 3 Transformer Addition	1,065	MECO-WP-1401A

Maui Electric Company, Limited

Test Year 2007

SPECIFIC PROJECTS OVER $1,000,000 AND LESS THAN $2,500,000
TO BE ADDED TO PLANT

($ Thousands)

	(A) Project No.	(B) Project Description	(C) Estimated Plant Additions	(D) Reference
1	M0000697	69kV Waikapu Relocation	1,573	MECO-WP-1401B
2	M0000809	Kihei Unit Substation #4 Addition	1,148	MECO-WP-1401B

Maui Electric Company, Limited

2006

PLANT RETIREMENTS

($ Thousands)

		(A)	(B)	(C)	(D)	(E)
		2006				
		Maui	Lanai	Molokai	Total	Reference
1	Production Plant	22	-	-	22	MECO-WP-1404A
2	Transmission Plant	72	-	-	72	MECO-WP-1404A
3	Distribution	493	6	7	506	MECO-WP-1404A
4	General Plant	436	-	4	440	MECO-WP-1404A
5	Total	1,022	6	11	1,040	MECO-WP-1404A

Note: General Plant Include Vehicles

Maui Electric Company, Limited

2007

PLANT RETIREMENTS

($ Thousands)

		(A)	(B)	(C)	(D)	(E)
				2007		
		Maui	Lanai	Molokai	Total	Reference
1	Production Plant	22	-	-	22	MECO-WP-1404A
2	Transmission Plant	72	-	-	72	MECO-WP-1404A
3	Distribution Plant	493	6	7	506	MECO-WP-1404A
4	General Plant	431	-	37	468	MECO-WP-1404A
5	Total	1,018	6	44	1,068	MECO-WP-1404A

Note: General Plant Include Vehicles

Maui Electric Company, Limited

2006 and 2007

PROPERTY HELD FOR FUTURE USE

($ Thousands)

	(A)	(B)
1	Recorded balance - 12/31/05	$2,633
2	No Estimated Changes in 2006	
3	Estimated balance - 12/31/06	$2,633
4	No Estimated Changes in 2007	
5	Estimated balance - 12/31/07	$2,633

Maui Electric Company, Limited

2006 and 2007

PROPERTY HELD FOR FUTURE USE

($ Thousands)

	(A)	(B)	(C)	(D)	(E)
	Name of Site	Size (Acres)	Year Acquired	Proposed Service Date	Total Cost
1	Waena Power Plant Site	67	1996	2011	$2,633

Maui Electric Company, Limited

2006

CONTRIBUTIONS IN AID OF CONSTRUCTION

($ Thousands)

		(A)	(B)	(C)	(D)	(E)
		Maui	Lanai	Molokai	Total	Reference
1	Receipts	2,856	37	20	2,913	MECO-WP-1406A
2	Transfers from Customer Advances	119	51	592	762	MECO-WP-1406B
3	Net Cash CIAC	2,975	88	612	3,675	MECO-WP-1406C
4	In-Kind	6,769	-	-	6,769	MECO-WP-1406D

Maui Electric Company, Limited

2007

CONTRIBUTIONS IN AID OF CONSTRUCTION

($ Thousands)

		(A)	(B)	(C)	(D)	(E)
		Maui	Lanai	Molokai	Total	Reference
1	Receipts	1,915	75	328	2,318	MECO-WP-1406C
2	*Transfers from Customer Advances*	212	-	108	320	MECO-WP-1406B
3	Net Cash CIAC	2,127	75	436	2,638	MECO-WP-1406C
4	In-Kind	6,931	-	-	6,931	MECO-WP-1406D

Maui Electric Company, Limited

2006

CUSTOMER ADVANCES

($ Thousands)

		(A) Maui	(B) Lanai	(C) Molokai	(D) Total	(E) Reference
1	Receipts	1,120	54	47	1,221	MECO-WP-1407A
2	Refunds	(1,499)	(187)	(61)	(1,747)	MECO-WP-1407B
3	Transfers to CIAC	(119)	(51)	(592)	(762)	MECO-WP-1406B

Maui Electric Company, Limited

2007

CUSTOMER ADVANCES

($ Thousands)

		(A) Maui	(B) Lanai	(C) Molokai	(D) Total	(E) Reference
1	Receipts	1,198	59	50	1,307	MECO-WP-1407A
2	Refunds	(587)	(12)	(3)	(602)	MECO-WP-1407B
3	Transfers to CIAC	(212)	-	(108)	(320)	MECO-WP-1406B

MECO T-15
DOCKET NO. 2006-0387

TESTIMONY OF
GAYLE T. OHASHI

DIRECTOR, FINANCIAL ANALYSIS
MANAGEMENT ACCOUNTING AND FINANCIAL SERVICES
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Rate Base

INTRODUCTION

Q. Please state your name and business address.

A. My name is Gayle T. Ohashi and my business address is 900 Richards Street, Honolulu, Hawaii 96813.

Q. By whom are you employed and in what capacity?

A. I am the Director of the Financial Analysis Division at Hawaiian Electric Company, Inc. ("HECO"). MECO-1500 provides my educational background and work experience.

Q. What is your area of responsibility in this proceeding?

A. My testimony will present Maui Electric Company, Ltd.'s ("MECO" or "Company") estimated average rate base for the test year and the working cash calculation included in the estimated average rate base.

AVERAGE RATE BASE

Q. What is the Company's estimate of the consolidated average rate base for the test year 2007 for the Maui, Molokai and Lanai Divisions?

A. The test year 2007 consolidated average rate base at proposed rates is estimated to be $386,040,000 as shown on MECO-1501.

Q. What is the Company's estimate of the average rate base for the test year 2007 for each of the three divisions?

A. The average rate base for the Maui Division is $358,023,000 as shown on MECO-1502. The average rate base for the Lanai Division is $13,251,000 as shown on MECO-1508. The average rate base for the Molokai Division is $14,767,000 as shown on MECO-1514.

Q. What is rate base?

A. Rate base is the net investment that is used or useful for public utility purposes and that has been funded by the Company's investors. Consistent with §269-16(b) of the Hawaii Revised Statutes, which requires "...a fair return on the property of the utility actually used or useful for public utility purposes", investors should have the opportunity to earn a fair rate of return on rate base (i.e., their investment).

Rate Base Calculation

Q. How is the rate base calculated in this docket?

A. For the 2007 test year, the Company calculated an average rate base which is the sum of the average balances of "investments in assets" less the sum of the average balances of "funds from non-investors." I will define these terms later in my testimony. The rate base is calculated specifically for each of the three divisions and then totaled for a consolidated rate base for MECO.

MECO generally calculates the test year rate base in accordance with the concepts adopted and/or accepted by the Commission in prior rate case decisions, including Decision and Order No. 16922 (dated April 6, 1999) in Docket No. 97-0346 ("MECO 1999 Decision"), MECO's test year 1999 rate case; Decision and Order No. 16134 (dated December 23, 1997) in Docket No. 96-0040, MECO's test year 1997 rate case; Decision and Order No. 15544 (dated April 28, 1997) in Docket No. 94-0345, MECO's test year 1996 rate case; and Decision and Order No. 13429 (dated August 5, 1994) in Docket No. 7000, MECO's 1992 and 1993 two-year test period rate case.

Q. How are the average balances for the rate base items calculated?

A. The average balance of each of the components of rate base is equal to the sum of the estimated 2006 and estimated 2007 year-end balances divided by two. Later in my testimony, I will describe the calculation of the 2006 and 2007 year-end balances for each rate base item or will reference the appropriate MECO witness testimony that contains this information.

INVESTMENTS IN ASSETS

Q. What are investments in assets?

A. Investments in assets include all investments necessary to provide reliable electric service to MECO's customers. Both investors and non-investors pay for these investments.

Q. What items are included in investments in assets?

A. Investments in assets consist of the following items:

1) Net cost of plant in service
2) Property held for future use
3) Fuel inventory
4) Materials and supplies inventories
5) Unamortized net Statements of Financial Accounting Standards ("SFAS") No. 109 regulatory asset
6) Pension asset
7) Other post retirement benefits other than pensions ("OPEB") amount
8) Unamortized system development costs, and
9) Working cash

Q. Are there rate base components that MECO proposes to include in the test year rate base in this proceeding that were not included in rate base in any prior MECO rate cases?

A. Yes. MECO did not previously forecast or include any unamortized system development costs, pension asset and OPEB amount. These components will be discussed later in my testimony.

1) Net Cost of Plant in Service

Q. What is the test year estimate of the average net cost of plant in service?

A. The estimated average net cost of plant in service for the test year 2007 is $398,136,000 for the Maui Division, as shown on MECO-1503, $15,187,000 for the Lanai Division, as shown on MECO-1509, and $18,039,000 for the Molokai Division, as shown on MECO-1515, for a total consolidated average net cost of plant in service of $431,361,000, as shown on MECO-1501.

Q. Please describe net cost of plant in service.

A. Net cost of plant in service is comprised of the gross plant in service less accumulated depreciation.

Q. What is gross plant in service?

A. The gross plant in service is the original cost of plant assets. The original cost of plant assets includes the cost of equipment, construction and all other costs necessary for the projects and investments to be used or useful for public utility purposes.

Q. What is accumulated depreciation?

A. Accumulated depreciation is the cumulative amount of depreciation that has been expensed in the past. Depreciation is the allocation of a portion of the original cost of the asset to each period in the estimated useful life of that asset. Part of the accumulated depreciation is reclassified as a cost of removal regulatory liability for financial reporting purposes, and part of the cost of removal regulatory liability is reclassified as asset retirement obligations for financial reporting purposes. The details of depreciation, accumulated depreciation, and the associated financial reporting reclassifications are discussed by Mr. Matsunaga in MECO T-12.

Q. Why is accumulated depreciation deducted from the original cost of assets?

A. Because the Company recovers depreciation through its rates and revenues, ratepayers have paid for the accumulated depreciation amount. As a result, MECO's investors should not earn a return on this amount (i.e., this amount should be removed as part of MECO's rate base upon which a rate of return is established).

Q. How is the estimated average net cost of plant in service calculated?

A. The starting point is the recorded net cost of plant in service at December 31, 2005. That amount is derived by subtracting accumulated depreciation and the regulatory liability for removal costs from gross plant in service at December 31, 2005. From this amount, we then made the following adjustments to determine the end-of-year 2006 estimates:

1) Add net plant additions (additions including in-kind contributions in aid of construction ("CIAC") presented by Ms. Arase in MECO T-14),
2) Add costs of removal of plant (presented by Ms. Arase in MECO T-14),
3) Subtract salvage value (presented by Mr. Matsunaga in MECO T-12), and
4) Subtract depreciation accrual (presented by Mr. Matsunaga in MECO T-12).

This resulting net amount is the estimated net cost of plant in service at December 31, 2006. The process is then repeated for the 2007 test year to determine the estimated net cost of plant in service at December 31, 2007. The average net cost of plant in service for test year 2007 is then calculated by dividing the sum of the estimated 2006 end-of-year balance and the 2007 end-of-year balance by two.

Q. Why is the net cost of plant in service included in rate base?

A. The net cost of plant in service represents the Company's unrecovered investment in plant necessary to provide electric service.

Q. Did the Commission allow the inclusion of net cost of plant in service in rate base in MECO's last rate case (1999 test year)?

A. Yes. The Commission included net cost of plant in service in determining rate base in the MECO 1999 Decision.

2) Property Held for Future Use

Q. What is the test year estimate of the average property held for future use?

A. Average property held for future use for test year 2007 is $2,633,000, as shown on MECO-1501 and MECO-1502. This applies only to the Maui Division, as there is no property held for future use for the Lanai or Molokai Divisions.

Q. What is property held for future use?

A. Property held for future use is property owned by MECO and held for future utility purposes. Ms. Arase explains the details of property held for future use in MECO T-14.

Q. How is the average balance of property held for future use calculated?

A. Ms. Arase describes the calculation of average balance of property held for future use in MECO T-14.

Q. Why is property held for future use included in rate base?

A. Property held for future use represents the Company's investment in sites needed to provide electric service in the future. The smooth operation of the utility sometimes requires the acquisition of property before it is needed.

Q. Did the Commission allow the inclusion of property held for future use in rate base in MECO's last rate case (1999 test year)?

A. Yes. The Commission included property held for future use in determining rate base in the MECO 1999 Decision.

3) Fuel Inventory

Q. What is the test year estimate of the average fuel inventory?

A. The estimated average fuel inventory for test year 2007 is $14,629,000 for the Maui Division, as shown on MECO-1502, $550,000 for the Lanai Division, as shown on MECO-1508, and $632,000 for the Molokai Division, as shown on MECO-1514, for a total consolidated average fuel inventory of $15,811,000, as shown on MECO-1501.

Q. What is fuel inventory?

A. Fuel inventory is the Company's investment in a supply of fuel held in inventory. Mr. Sakuda explains the details of fuel inventory in MECO T-4.

Q. Why is fuel inventory included in rate base?

A. An investment in fuel inventory is required in order to ensure a sufficient supply of fuel for the Company's power plants so that the Company can provide reliable electric service to its customers.

Q. Did the Commission allow the inclusion of fuel inventory in rate base in MECO's last rate case (1999 test year)?

A. Yes. The Commission included fuel inventory in determining rate base in the MECO 1999 Decision. The Commission has also included fuel inventory in numerous other rate cases for HECO and Hawaii Electric Light Company, Inc. ("HELCO").

4) Materials and Supplies Inventories

Q. What is the test year estimate of the average materials and supplies inventories?

A. The Company's estimated average materials and supplies inventories (for production, transmission and distribution and lube oil) for test year 2007 is $11,263,000 for the Maui Division, as shown on MECO-1504, $193,000 for the Lanai Division, as shown on MECO-1510, and $195,000 for the Molokai Division, as shown on MECO-1516, for a total consolidated average materials and supplies inventories amount of $11,651,000, as shown on MECO-1501. The test year estimates include an adjustment for the payment lag associated with the investment in inventory.

Q. What are materials and supplies inventories?

A. Materials and supplies inventories include production inventory, transmission and distribution inventory and lube oil inventory. Mr. Ribao discusses production and lube oil inventory in MECO T-5 and Mr. Herrera discusses transmission and distribution inventory in MECO T-6.

Q. How is the average balance of materials and supplies inventory calculated?

A. The 2006 and 2007 year-end balances before the adjustment for the payment lag for production and lube oil inventory, and then for transmission and distribution inventory, are described by Mr. Ribao and Mr. Herrera in MECO T-5 and MECO T-6, respectively. I will describe the adjustment for the payment lag.

Q. Why does the inventory balance include an adjustment for payment lag?

A. In Decision and Order No. 14412 (dated December 11, 1995) in Docket No. 7766, HECO's test year 1995 rate case, the Commission determined that materials and supplies inventory should be adjusted to reflect the payment lag associated with goods received but not yet paid for by HECO.

Q. Has the payment lag associated with inventory been an issue in any MECO rate case?

A. No. In past MECO rate cases, MECO captured the payment lag in the operations and maintenance ("O&M") non-labor payment lag and this treatment was accepted by all parties involved in that proceeding. However, the payment lag associated with inventory can be captured in either the O&M non-labor payment lag or as an adjustment to materials inventory. Although not previously raised as an issue in prior MECO rate cases, the payment lag has been an issue in past HECO rate cases, which resulted in HECO capturing the payment lag as an adjustment to materials inventory instead of through the O&M non-labor payment lag. As a result of this, for purposes of this proceeding, MECO has decided to be consistent with the treatment of the inventory payment lag used in the latest HECO rate cases (Docket No. 2006-0386, test year 2007 rate case; Docket No. 04-0113, test year 2005 rate case), and also be consistent with the treatment applied in Docket No. 05-0315, HELCO's 2006 test year rate case.

Q. How was the payment lag associated with inventory determined?

A. MECO performed a study of payments for inventory purchases to determine the length of time between when inventory is received and when payment is made. MECO tested a sample of 2005 inventory purchases and determined the payment lag for each item. Then, MECO calculated the dollar-weighted average days for the sample. The study is summarized on MECO-WP-1504, page 3.

Q. What was the result of the inventory payment lag study?

A. The payment lag days are approximately 33 days.

Q. How are the results of the inventory payment lag study used in determining the adjustment to the materials and supplies inventory?

A. The adjustment to the materials and supplies inventory is calculated by multiplying the forecasted daily additions to inventory for the 2007 test year by the inventory payment lag days of 33 days. The calculation of the inventory adjustment is shown on MECO-WP-1504, page 1 for the Maui Division, MECO-WP-1510, page 1 for the Lanai Division and MECO-WP-1516, page 1 for the Molokai Division.

Q. What is the test year payment lag adjustment to the materials and supplies inventory?

A. The estimated payment lag adjustment to the materials and supplies inventory for test year 2007 is (1) $846,000 for the Maui Division, comprised of a $309,000 adjustment to production inventory, a $454,000 adjustment to transmission and distribution inventory and a $83,000 adjustment to lube oil inventory as shown on MECO-1504 and MECO-WP-1504, (2) $21,000 for the Lanai Division, comprised of a $5,000 adjustment to production inventory, a $12,000 adjustment to transmission and distribution inventory and a $4,000 adjustment to lube oil inventory as shown on MECO-1510 and MECO-WP-1510, and (3) $35,000 for the Molokai Division, comprised of a $2,000 adjustment to production inventory, a $27,000 adjustment to transmission and distribution inventory and a $7,000 adjustment to lube oil inventory as shown on MECO-1516 and MECO-WP-1516.

Q. How does the payment lag adjustment to inventory affect the payment lag included in the working cash calculation discussed later in your testimony?

A. In theory, the O&M non-labor payment lag component in the working cash calculation, assuming that inventory is adjusted for the payment lag, is shorter than if the inventory payment lag had been accounted for in the O&M non-labor payment lag. Since the inventory balance represents only that portion of inventory that has been paid for, the working cash related to O&M non-labor reflects inventory charges to O&M from the "paid-up" inventory balance. O&M charges from inventory therefore have no payment lag in the current working cash lead-lag study provided in MECO-WP-1507.

Q. Why are materials and supplies inventories included in rate base?

A. An investment in an adequate supply of materials and supplies is necessary to ensure that the Company can effectively operate and maintain its electrical system to provide continuous and reliable service to its customers.

Q. Did the Commission allow the inclusion of materials and supplies inventory in rate base in MECO's last rate case (1999 test year)?

A. Yes. The Commission included materials and supplies inventory in determining rate base in the MECO 1999 Decision. The Commission has also included materials and supplies inventory in numerous other rate cases for HECO and HELCO.

<u>5) Unamortized Net SFAS 109 Regulatory Asset</u>

Q. What is the test year estimate of average unamortized net SFAS 109 regulatory asset?

A. The estimate for the unamortized net SFAS 109 regulatory asset is $7,972,000 for the Maui Division, as shown on MECO-1502, $429,000 for the Lanai Division, as shown on MECO-1508, and $518,000 for the Molokai Division, as shown on MECO-1514, for a total consolidated average unamortized net SFAS 109 regulatory asset of $8,918,000, as shown on MECO-1501.

Q. What is the unamortized net SFAS 109 regulatory asset?

A. As described by Mr. Okada in MECO T-13, the net regulatory asset is an accounting asset that came about due to the reporting requirements of SFAS 109.

Q. How was the average unamortized net SFAS 109 regulatory asset calculated?

A. Mr. Okada describes the calculation of average unamortized net SFAS 109 regulatory asset in MECO T-13.

Q. Why is the unamortized net SFAS 109 regulatory asset included in rate base?

A. As explained by Mr. Okada in MECO T-13, SFAS 109 requires the debt portion of the Allowance for Funds Used During Construction ("AFUDC") as well as any other item previously recorded on a net-of-tax basis, to be calculated and capitalized on a gross-of-tax basis. As a result, without some adjustment, plant in service would increase by the tax effect of the debt portion of AFUDC. However, instead of increasing plant in service, SFAS 109 requires this gross-up adjustment to a regulatory asset, with the offsetting credit to the deferred income tax liability account. Because the regulatory asset is offset by the corresponding increase in deferred taxes, there is no net rate base impact.

Q. Did the Commission allow the inclusion of unamortized net SFAS 109 regulatory asset in MECO's last rate case (1999 test year)?

A. Yes. The Commission included unamortized net SFAS 109 regulatory asset in determining rate base in the MECO 1999 Decision. The Commission has also included it in all of HECO and HELCO rate cases since the inception of SFAS 109.

6) Pension Asset

Q. What is the test year estimate of the average pension asset?

A. The estimated average pension asset is $3,093,000 for the Maui Division, as shown on MECO-1502, $90,000 for the Lanai Division, as shown on MECO-1508, and $139,000 for the Molokai Division, as shown on MECO-1514, for a total consolidated average pension asset of $3,321,000, as shown on MECO-1501.

Q. What is the pension asset?

A. The pension asset is an investment that results from the impact of the cumulative pension contributions made to the pension fund in excess of the cumulative pension costs recognized.

Q. Why is the pension asset included in rate base?

A. The pension asset is included in rate base because: (1) it is consistent with the previous ratemaking treatment of the pension expense, (2) it is the cumulative balance of investor-provided funds in excess of the recognized pension costs that benefits ratepayers, and (3) it is an asset that is used or useful for providing electric utility service, as the pension plan is an integral part of the Company's compensation package to its employees and is necessary to attract and retain quality employees that are engaged in the provision of electric service to the public. Mr. Matsunaga further discusses the basis for the inclusion of this asset in rate base in MECO T-9. Ms. Price discusses the benefits of the Company's pension plan in MECO T-10 and Ms. Sekimura discusses the importance to investors of including the pension asset in rate base in MECO T-17.

Q. Did the Commission allow the inclusion of a pension asset in MECO's last rate case (1999 test year)?

A. No. In MECO's 1999 test year rate case, MECO was in a pension liability situation (the cumulative pension contributions were less than the cumulative pension costs recognized), therefore, MECO proposed to treat the pension liability as a deduction in the calculation of rate base. In the MECO 1999 Decision, the final rate base included a deduction for pension liability.

<u>7) OPEB Amount</u>

Q. What is the test year estimate of the average OPEB amount?

A. The test year estimate of the average OPEB amount is $0 for the Maui, Lanai and Molokai Divisions, as shown on MECO-1502, MECO-1508 and MECO-1514, respectively, and MECO-1501.

Q. What is the OPEB amount?

A. The OPEB amount is an investment that results from the impact of the cumulative OPEB contributions made net of the cumulative OPEB costs recognized. At the beginning of the test year and at the end of the test year, cumulative OPEB contributions equal the cumulative OPEB costs recognized. As a result, the test year amount for the OPEB amount is $0 in this proceeding. Mr. Matsunaga further discusses the proposed ratemaking treatment of the OPEB costs in MECO T-9. Ms. Price discusses the benefits of the Company's OPEB plan in MECO T-10.

8) Unamortized System Development Costs

Q. What is the test year estimate of average unamortized system development costs?

A. The test year estimate of unamortized system development costs is $217,000 for the Maui Division, as shown on MECO-1502, $7,000 for the Lanai Division, as shown on MECO-1508, and $10,000 for the Molokai Division, as shown on MECO-1514, for a total consolidated average unamortized system development costs amount of $233,000, as shown on MECO-1501.

Q. What is included in unamortized system development costs?

A. The unamortized system development costs relate to the Human Resources Suite ("HRS") project (Phase 1) as presented by Ms. Price in MECO T-10.

Q. Why is unamortized system development costs included in rate base?

A. In Decision and Order No. 18365, Docket No. 99-0207 (HELCO's Test Year 2000 rate case), the Commission ruled that its pre-approval is required before any computer software development project costs may be deferred and amortized for ratemaking purposes. For the HRS project, the Company filed its Application in Docket No. 2006-0003 on January 3, 2006, requesting Commission approval of its proposed accounting treatment to defer costs. The project is estimated to be completed and in service in November 2007. A Commission decision is still pending on that application. Ms. Price discusses the current status of this docket in MECO T-10.

As presented by Mr. Matsunaga in MECO T-9, the unamortized costs of computer software development projects are similar to undepreciated costs of capitalized plant and equipment, and should be included in the calculation of rate base. Rate base treatment is appropriate because investors have provided the funds up front to develop the computer software systems which are expected to be in service during the test year. As such, the unamortized system development costs are appropriately included in rate base and allow investors the opportunity to earn a fair return on their investment.

Q. Did the Commission allow the inclusion of unamortized system development costs in rate base in MECO's last rate case (1999 test year)?

A. No. In the 1999 test year rate case, MECO did not forecast nor include unamortized system development costs in the rate base.

9) Working Cash

Q. What is the test year estimate of working cash at present and proposed rates?

A. The test year estimate of working cash at present and proposed rates is $7,343,000 and $7,136,000 for the Maui Division, as shown on MECO-1507, $338,000 and $332,000 for the Lanai Division, as shown on MECO-1513, and $295,000 and $287,000 for the Molokai Division, as shown on MECO-1519.

Q. What is working cash?

A. Working cash is the net cash needed for smooth fiscal operations. Working cash is comprised of sources and uses of cash from operations. Electric service provided before customers pay for services is a use of cash. This is also referred to as the revenue collection lag. Goods and services received before suppliers are paid is a source of cash. This is also referred to as the payment lag.

Q. Why is working cash included in rate base?

A. Working cash is included in rate base because it represents an investment which enables the Company to have sufficient funds to pay suppliers and conduct other business necessary for the provision of electric service to consumers. Inclusion of the working cash investment in rate base recognizes the timing of cash flows through the Company.

Q. What are the elements of working cash?

A. Working cash is comprised of the net of the revenue collection lag and the payment lag. I will discuss these elements in detail in the following sections.

Q. Is the calculation of working cash consistent with the methodology used in prior MECO rate cases?

A. Yes. The methodology that I have used to calculate working cash in this rate case is consistent with the methodology used in MECO's 1999 test year rate case. However, I have included certain refinements and modifications which I will discuss in detail in the following sections.

Revenue Collection Lag

Q. What is the test year estimate of the revenue collection lag days?

A. As discussed by Ms. Suzuki in MECO T-7, the estimated revenue collection lag days for test year 2007 is 36 days. See also column A of MECO-1507, 1513 and 1519.

Q. What is a revenue collection lag?

A. The revenue collection lag is the time between the provision of electric service and the receipt of cash for that service. This lag represents the average period of time the Company extends credit to its customers for electric service delivered.

Q. What is the working cash impact associated with the revenue collection lag?

A. The working cash impact associated with the revenue collection lag is the cash needed because services are provided to customers before customers pay for the services.

Q. How is the working cash requirement associated with the revenue collection lag calculated?

A. The revenue collection lag is net against the payment lag, and then the net payment lag days are applied to each of the payment categories discussed later in my testimony.

Q. Why are depreciation and amortization, interest on customer deposits, and operating income excluded from revenues in the revenue collection lag calculation?

A. A<u>ll</u> revenues should be included in the calculation of working cash needs associated with the revenue collection lag. However, the Company recognizes that the Commission has disallowed these items in the determination of working cash needs in previous decisions. Therefore, the Company has excluded these items to simplify the issues and to speed the regulatory process in this case. The

Company reserves the right, however, to bring these issues before the Commission in the future.

Payment Lag

Q. What is a payment lag?

A. A payment lag occurs when the Company incurs an obligation to pay for an item or service before the Company actually pays for it. Payment lags can be associated with purchases of goods or services or for payments of costs of doing business, such as taxes.

Q. What is the working cash impact associated with the payment lag?

A. The working cash impact associated with the payment lag depends on when the Company is required to pay for expenditures. Generally, payments are made after the goods or services have been received. Therefore, payment lags are a source of working cash.

Q. What is included in the payment lag?

A. The payment lag includes six categories:

1) Fuel purchases,
2) O&M labor,
3) Purchased power,
4) O&M non-labor,
5) Revenue taxes, and
6) Income taxes.

Q. Why has the Company limited the payment lag to these six items in this docket?

A. In general, all payments should be included in the calculation of working cash sources from payment lags. However, the Company has excluded those items that have been excluded by the Commission in previous decisions in the determination of working cash. Limiting the working cash needs to these six categories of payments is consistent with Commission decisions, including the MECO 1999 Decision. If all revenues were included in the calculation of the revenue collection lag, it would be appropriate to include all payments in the payment lag calculation.

Q. How are the working cash sources calculated for the six categories of payments?

A. The working cash sources for the six categories of payments are calculated as follows:

1. Determine the payment lag days for each category.
2. Subtract the payment lag days from the revenue collection lag days to calculate the net collection lag days.
3. Estimate the total annual expenditures for the test year for each category based on the test year expense estimates.
4. Determine the average daily expenditures by dividing the total annual expenditures for each payment category by 365 days.
5. Multiply each payment's respective average daily expenditure by its net payment lag days.

See MECO-1507 and MECO-WP-1507. I will describe the working cash calculation for each payment category in the next section.

1) Working Cash for Fuel Purchases

Q. What is the test year estimate of working cash required for fuel purchases?

A. The test year estimate of working cash required for fuel purchases is $9,125,000 for the Maui Division, as shown on MECO-1507 (columns F and H), $355,000 for the Lanai Division, as shown on MECO-1513 (columns F and H), and $318,000 for the Molokai Division, as shown on MECO-1519 (columns F and H).

Q. What is the test year estimate of fuel purchases?

A. The estimated test year amount of fuel purchases is $166,525,000 for the Maui Division, as shown on MECO-1507 (column D), $6,173,000 for the Lanai Division, as shown on MECO-1513 (column D), and $7,247,000 for the Molokai Division, as shown on MECO-1519 (column D).

Q. What is the test year estimate of the fuel payment lag days?

A. The test year estimate of the fuel payment lag days is 16 for the Maui Division, as shown on MECO-1507 (column B), 15 for the Lanai Division, as shown on MECO-1513 (column B), and 20 for the Molokai Division, as shown on MECO-1519 (column B).

Q. How were the payment lag days for fuel payments calculated?

A. The payment lag days for fuel payments were calculated by determining the vendors who will supply fuel to the Company, determining the proportions of fuel expense attributable to each vendor, determining the payment lag days for each vendor, and calculating the weighted average payment lag days.

Q. How were the vendors who will supply fuel determined?

A. The vendors who are expected to supply fuel to the Company in the test year were determined based on the contracts for fuel and fuel-related services and discussions with HECO's Fuels Resources Division.

Q. How were the proportions of fuel expense attributable to each vendor determined?

A. The proportions were determined based on a breakdown by vendor of spot fuel price for each type of fuel and the forecasts of fuel consumption by fuel type. HECO's Fuels Resources Division provided a breakdown by vendor of spot fuel prices for each type of fuel consumed. HECO's Generation Planning Division provided forecasts of fuel consumption by fuel type.

Q. How were the payment lag days for each vendor determined?

A. The payment lag days for Chevron, Tesoro and Lanai Oil Company were determined based on a study of 2005 payments made. These vendors are paid by wire, and as such they have no check clearing lag. The payment lag days for Maui Oil Company was determined based on a study of payments made in 2004 through early 2006. This vendor is paid by check so the check clearing lag was also determined.

Q. How was the weighted average payment lag days calculated?

A. The weighted average payment lag days was calculated by taking the sum of the proportions for each vendor multiplied by the payment lag. The calculation of the fuel payment lag days is shown on MECO-WP-1507 (page 1) for the Maui Division, MECO-WP-1513 (page 1) for the Lanai Division, and MECO-WP-1519 (page 1) for the Molokai Division.

Q. Is the calculation of the working cash for fuel purchases for the 2007 test year consistent with the method of calculation used in MECO's last rate case (1999 test year)?

A. Yes. The methodology is consistent with the methodology used in MECO's 1999 test year rate case.

2) Working Cash for O&M Labor

Q. What is the test year estimate of working cash required for O&M labor?

A. The test year estimate of working cash required for O&M labor is $1,082,000 for the Maui Division, as shown on MECO-1507 (columns F and H), $48,000 for the Lanai Division, as shown on MECO-1513 (columns F and H), and $60,000 for the Molokai Division, as shown on MECO-1519 (columns F and H).

Q. What is the test year estimate of O&M labor?

A. The estimated test year amount of O&M labor is $16,451,000 for the Maui Division, as shown on MECO-1507 (column D), $724,000 for the Lanai Division, as shown on MECO-1513 (column D), and $916,000 for the Molokai Division, as shown on MECO-1519 (column D).

Q. What is the test year estimate of the O&M labor payment lag days?

A. The test year estimate of the O&M labor payment lag days is 12 for the Maui, Lanai and Molokai Divisions, as shown on MECO-1507 (column B), MECO-1513 (column B) and MECO-1519 (column B), respectively.

Q. How were the payment lag days for O&M labor calculated?

A. The payment lag days for O&M labor were calculated by determining the proportions of significant types of disbursements for labor, determining the payment lag days for each type of disbursement, and then calculating the weighted average payment lag days.

Q. What are the significant types of labor disbursements?

A. The significant types of labor disbursements are payments to employees by check or direct deposit (including deposits to employees' credit union accounts), to the federal government for federal income tax withholding and for Federal Insurance Contribution Act and Medicare taxes ("FICA"), to the state government for state income tax withholding, and to the employee's Hawaiian Electric Industries Retirement Savings Plan ("HEIRS") account.

Q. How were the proportions of significant labor disbursements determined?

A. The proportions for significant labor disbursements were based on 2005 payroll data.

Q. How were the payment lag days for each type of disbursement determined?

A. The payment lag days presented in this rate case are based on the actual 2005 payroll schedule and payments.

Q. How were the weighted average payment lag days for O&M labor calculated?

A. MECO determined the weighted average payment lag days for O&M labor by calculating the sum of proportions of labor disbursements multiplied by the respective payment lag days (including check clearing lag days). The calculation of O&M labor payment lag days is shown on MECO-WP-1507 (page 9).

Q. Is the calculation of working cash for O&M labor consistent with the method of calculation used in MECO's last rate case (1999 test year)?

A. Yes.

3) <u>Working Cash Provided by Purchased Power</u>

Q. What is the test year estimate of working cash provided by purchased power?

A. The test year estimate of working cash provided by purchased power is $466,000 as shown on MECO-1507 (columns F and H) for the Maui Division. The Lanai and Molokai Divisions do not have any purchased power.

Q. What is the test year estimate of purchased power?

A. The estimated test year amount of purchased power is $33,982,000 as shown on MECO-1507 (column D).

Q. What is the test year estimate of the purchased power payment lag days?

A. The test year estimate of the purchased power payment lag days is 41 days, as shown on MECO-1507 (column B).

Q. How were the payment lag days for purchased power calculated?

A. The payment lag days for purchased power were calculated by obtaining the test year estimates of independent power producer ("IPP") payments, determining the respective payment lag days for each type of payment, and calculating the weighted average payment lag days. See Mr. Ribao's testimony in MECO T-5 for a discussion of the three IPPs that provide purchased power to the Maui Division.

Q. Who provided the test year estimates of IPP payments?

A. HECO's Generation Planning Division provided the estimates of IPP payments.

Q. How were the payment lag days for capacity and energy determined?

A. The payment lag days for capacity and energy were based on the terms of MECO's purchase power agreements with the respective IPPs.

Q. How were the weighted average payment lag days calculated?

A. The weighted average payment lag days were the sum of the proportion of payments for each type of payment to the IPPs multiplied by the payment lag days (including check clearing lag days). The calculation of purchased power payment lag days is shown on MECO-WP-1507 (page 6).

Q. Is the calculation of the purchased power payment lag days consistent with the method of calculation used in MECO's last rate case (1999 test year)?

A. Yes. The methodology used for the 2007 test year is consistent with the methodology used in MECO's 1999 test year rate case. However, in the 1999 test year rate case, the purchased power payment lag days were based on historical information whereas in the current study, the purchased power payment lag days were estimated based on forecasts of test year payments. Specifically, in MECO's 1999 test year rate case, the purchased power payment lag days were based on the payment lag days used in MECO's 1997 test year rate case (Docket No. 96-0040), which were calculated based on actual historical purchased power payments made to the various IPPs. In the current study, the payment lag days were calculated based on the expected payment schedule and payment due dates to the various IPPs.

4) Working Cash Required for O&M Non-labor

Q. What is the test year estimate of working cash required for O&M non-labor?

A. The test year estimate of working cash required for O&M non-labor is $316,000 for the Maui Division, as shown on MECO-1507 (columns F and H), $13,000 for the Lanai Division, as shown on MECO-1513 (columns F and H), and $18,000 for the Molokai Division, as shown on MECO-1519 (columns F and H).

Q. What is the test year estimate of O&M non-labor?

A. The estimated test year amount of O&M non-labor is $28,809,000 for the Maui Division, as shown on MECO-1507 (column D), $1,152,000 for the Lanai Division, as shown on MECO-1513 (column D), and $1,661,000 for the Molokai Division, as shown on MECO-1519 (column D).

Q. What is the test year estimate of the O&M non-labor payment lag days?

A. The test year estimate of the O&M non-labor payment lag days is 32 days for the Maui, Lanai and Molokai Divisions, as shown on MECO-1507 (column B), MECO-1513 (column B) and MECO-1519 (column B), respectively.

Q. How were the payment lag days for O&M non-labor calculated?

A. The payment lag days for O&M non-labor were calculated by obtaining the test year estimates of O&M non-labor expenses. Large O&M non-labor payments were separately identified and the payment lags for those items were determined. A sample of all other O&M non-labor expenses was then examined to determine the payment lag for the sample.

Q. What large O&M non-labor payments were separately identified?

A. Pension expense, OPEB, emission fees, and Electric Power Research Institute ("EPRI") dues were separately identified.

Q. What is the payment lag for pension expense?

A. The payment lag for pension expense is zero as shown on MECO-WP-1507 (page 23). Because the pension expense is recognized at the same time the net pension asset is credited and the pension asset is included in rate base, the net activity is reflected in the pension asset rather than as an item impacting working cash. In theory, because the pension asset is included in the calculation of rate base, ratepayers are credited the working cash impact of the pension cost at the same time the rate base (i.e., the pension asset) is decreased for the pension cost. As a result, there is no lag between the credit to the pension asset (reducing rate base) and the pension cost recognition. Individual payments to the pension fund do not directly correlate to specific pension cost recognition. The timing differences between the pension cost recognition and pension funding are in theory being recognized in the pension asset.

Q. What is the payment lag for OPEB expense?

A. Similar to pension expense, the payment lag for OPEB is zero as shown on MECO-WP-1507 (page 23). Because the OPEB cost is recognized at the same time the OPEB amount is credited, the net activity is reflected in the OPEB amount which is included in rate base rather than as an item impacting working cash.

Q. What is the payment lag for emission fees?

A. The payment lag for emission fees is 306 days as shown on MECO-WP-1507 (page 23).

Q. How was the payment lag for emission fees determined?

A. The payment lag for emission fees was based on historical emission fee payments from 2005. Details of the study are provided in MECO-WP-1507 (page 24).

Q. What is the payment lag for EPRI dues?

A. The payment lag for EPRI dues is 22 days as shown on MECO-WP-1507 (page 23).

Q. How was the payment lag for EPRI dues determined?

A. The payment lag for EPRI dues was based on historical EPRI payments from 2005. Details of the study are provided on MECO-WP-1507 (page 25).

Q. Is it reasonable to use payment lag days for EPRI dues based on the 2005 EPRI membership agreement for the test year? Please explain.

A. Yes. MECO has entered into a new multi-year membership agreement with EPRI which began on January 1, 2007. The payment terms of this new agreement are consistent with the payment terms in the agreement with EPRI in 2005. Therefore, the use of payment lag days based on 2005 payments appears to be appropriate. Further discussion of MECO's EPRI membership is presented by Mr. Matsunaga in MECO T-9.

Q. How was the payment lag for other O&M non-labor determined?

A. First, the Company tested a sample of 2005 O&M non-labor transactions. The sample was a random sample of the data base of 2005 O&M expenses. Second, the payment lag for each item in the sample was determined. Then, we calculated the dollar weighted average days for the sample. Payment lag days for all other O&M non-labor were based on this study. Details of the study are provided on MECO-WP-1507 (page 26).

Q. How were the weighted average payment lag days for O&M non-labor calculated?

A. The weighted average payment lag days is the sum of the proportions of the separately-identified large 2007 test year O&M non-labor payments and the sample of all other 2007 test year O&M non-labor payments multiplied by the respective payment lag days (including check clearing lag days). Details of the study and calculation of O&M non-labor payment lag days is shown on MECO-WP-1507 (page 23).

Q. Is the calculation of the O&M non-labor payment lag days consistent with the method of calculation used in MECO's last rate case (1999 test year)?

A. Yes. However, in the current study, MECO made three modifications to refine the calculation of working cash for O&M non-labor.

Q. Please identify the three modifications.

A. One modification was that MECO was able to isolate the study to O&M non-labor charges. In past studies of O&M non-labor payment lag, MECO used a population of charges to accounts payable due to limitations in the ability to access the data base of O&M expense charges. As a result of a new payment system implemented in 1999, MECO was able to refine the O&M non-labor payment lag study. Sampling the population of O&M non-labor expenses, rather than sampling a population of accounts payable charges, increased the accuracy of the O&M non-labor payment lag days estimate.

Second, MECO was able to determine which O&M non-labor expense in the study were charges from materials and supplies inventory. This allowed MECO to adjust the working cash estimate to exclude the payment lag associated with inventory. Because the working cash estimate does not include the payment lag associated with inventory, it is appropriate to reflect the inventory payment lag as an adjustment to materials and supplies inventory as discussed earlier in my testimony.

A third change was in the significant O&M non-labor payments (pension expense, OPEB, emission fees, and EPRI dues) which were separately identified and not included in the sampling of O&M non-labor payments as I discussed earlier. Separately identifying large O&M non-labor payments helps to minimize the potential for distortion in the payment lag study that may result if these large payments are picked up in the general sampling.

5) Working Cash Provided by Revenue Taxes

Q. What is the test year estimate of working cash provided by revenue taxes?

A. The test year estimate of working cash provided by revenue taxes is $2,601,000 at present rates and $2,739,000 at proposed rates for the Maui Division, as shown on MECO-1507 (columns F and H). For the Lanai Division, it is $79,000 at present rates and $83,000 at proposed rates as shown on MECO-1513 (columns F and H). For the Molokai Division, it is $99,000 at present rates and $104,000 at proposed rates as shown on MECO-1519 (columns F and H).

Q. What is the test year estimate of revenue taxes?

A. The estimated annual amount of revenue taxes is $29,665,000 at present rates and $31,237,000 at proposed rates as shown on MECO-1507 (column D) for the Maui Division. For the Lanai Division, it is $896,000 at present rates and $944,000 at proposed rates as shown on MECO-1513 (column D). For the Molokai Division, it is $1,129,000 at present rates and $1,189,000 at proposed rates as shown on MECO-1519 (column D).

Q. What is the test year estimate of the revenue tax payment lag days?

A. The test year estimate of the revenue tax payment lag days is 68 days for the Maui, Lanai and Molokai Divisions, as shown on MECO-1507 (column B), MECO-1513 (column B) and MECO-1519 (column B), respectively.

Q. How were the payment lag days for revenue tax payments calculated?

A. The payment lag days for revenue tax payments were calculated by first determining the proportions of various revenue tax payments, then determining the payment lags for the various revenue tax payments, and finally calculating the weighted average payment lag days.

Q. What were the various revenue tax payments?

A. Revenue tax payments include the Public Service Company ("PSC") tax, Franchise Royalty Tax, and the Public Utilities Commission ("PUC") fee.

Q. How were the proportions of revenue tax payments determined?

A. The proportions of revenue tax payments were determined based on the respective tax rates.

Q. How were the payment lags for the Franchise Royalty Tax and the PUC fee determined?

A. The payment lags for the Franchise Royalty Tax and the PUC fee were based on actual 2005 payments. The check clearing lag days for each type of revenue tax payment were based on a study of the 2005 revenue tax payments. The calculation of the payment lag days for the Franchise Royalty Tax and the PUC fee are shown on MECO-WP-1507 (page 29).

Q. How were the payment lag days for the PSC tax calculated?

A. The payment lag days were calculated by determining the proportions of state and county tax payments, determining the payment lag days for state and county tax payments, and then calculating the weighted average payment lag days.

Q. How were the proportions of state and county tax payments determined?

A. The proportions of state and county tax payments were determined by the respective tax rates. The tax rate is 5.885%, of which 4% is paid to the state and 1.885% is paid to the county.

Q. How was the payment lag for each type of tax payment determined?

A. The payment lag and check clearing lag days were based on actual 2005 monthly payments made to the state and county.

Q. How were the weighted average payment lag days for the PSC tax calculated?

A. The weighted average payment lag days were the sum of the proportions of the payments made to the state and county multiplied by their respective payment lag. The calculation of the payment lag days for the PSC tax is shown on MECO-WP-1507 (page 28).

Q. How was the weighted average payment lag days for total revenue taxes calculated?

A. The weighted average payment lag days are the sum of the proportions of revenue taxes multiplied by the respective payment lag days (including check clearing lag days). The calculation of revenue tax payment lag days is shown on MECO-WP-1507 (page 27).

Q. Was the calculation of the revenue tax payment lag days consistent with the method of calculation used in MECO's last rate case (1999 test year)?

A. Yes. The methodology used for the 2007 test year is consistent with the methodology used in MECO's 1999 test year rate case.

6) Working Cash Provided by Income Taxes

Q. What is the test year estimate of working cash provided by income taxes?

A. The test year estimate of working cash provided by income taxes is $113,000 at present rates and $182,000 at proposed rates as shown on MECO-1507 (columns F and H) for the Maui Division. For the Lanai Division, it is $(1,000) at present rates and $1,000 at proposed rates as shown on MECO-1513 (columns F and H). For the Molokai Division, it is $2,000 at present rates and $5,000 at proposed rates as shown on MECO-1519 (columns F and H).

Q. What is the test year estimate of income taxes?

A. The estimated annual amount of income taxes is $10,305,000 at present rates and $16,599,000 at proposed rates as shown on MECO-1507 (column D) for the Maui Division. For the Lanai Division, it is $(126,000) at present rates and $65,000 at proposed rates as shown on MECO-1513 (column D). For the Molokai Division, it is $182,000 at present rates and $423,000 at proposed rates as shown on MECO-1519 (column D).

Q. What is the test year estimate of the income tax payment lag days?

A. The test year estimate of the income tax payment lag days is 40 days for the Maui, Lanai and Molokai Divisions, as shown on MECO-1507 (column B), MECO-1513 (column B) and MECO-1519 (column B), respectively.

Q. How were the payment lag days for income taxes calculated?

A. The payment lag days for income taxes were calculated by determining the proportions of federal and state income tax payments, determining the payment lag days for federal and state income tax payments, and calculating the weighted average payment lag days.

Q. How were the proportions of federal and state income tax payments determined?

A. The proportions of federal and state income tax payments were determined by the respective effective tax rates. Effective tax rates take into consideration the deductibility of state income taxes.

Q. How was the payment lag for each respective type of income tax payment determined?

A. The payment lag for each type of income tax payment was determined based on its respective tax regulation and projected payments for 2007. There were no check clearing lag days because payments are made by electronic funds transfer.

Q. How were the weighted average payment lag days calculated?

A. The weighted average payment lag days were the sum of the proportions of federal and state income taxes multiplied by their respective payment lags. The calculation of the payment lag days for income taxes is shown on MECO-WP-1507 (page 30).

Q. Is the calculation of the income tax payment lag days consistent with the method of calculation used in MECO's last rate case (1999 test year)?

A. Yes. The methodology is consistent with the methodology used in MECO's 1999 test year rate case.

<u>FUNDS FROM NON-INVESTORS</u>

Q. What are funds from non-investors?

A. Funds from non-investors are funds that are invested in assets to provide reliable electric service that are from sources other than investors.

Q. What are the categories of funds from non-investors?

A. The categories of funds from non-investors are:

1) Unamortized contributions in aid of construction (CIAC),
2) Customer advances for construction,
3) Customer deposits,
4) Accumulated deferred income taxes, and
5) Unamortized investment tax credits.

Q. Why are funds provided by non-investors deducted from the investment in assets in determining rate base?

A. Investors and non-investors provide the funds that are invested in the assets needed for the Company to provide reliable electric service. Funds provided by non-investors are deducted from investments in assets to determine the amount of investor-provided funds. The investor-funded portion of investments in assets servicing customers (i.e., rate base) is the amount on which investors are entitled to receive a fair return. Therefore, rate base represents only the portion of investment in assets that are funded by investors.

1) Unamortized CIAC

Q. What is the test year estimate of average unamortized CIAC?

A. The estimated average unamortized CIAC for test year 2007 is $50,082,000 for the Maui Division, as shown on MECO-1505, $1,983,000 for the Lanai Division, as shown on MECO-1511, and $3,301,000 for the Molokai Division, as shown on MECO-1517, for a total consolidated test year estimate of average unamortized CIAC of $55,365,000, as shown on MECO-1501.

Q. What is CIAC?

A. CIAC is money or property that a developer or customer contributes to the Company to fund a utility capital project. As specified in the Company's tariff, the contribution is nonrefundable. Amortization of CIAC offsets depreciation expense. Ms. Arase discusses CIAC and the amortization of CIAC in detail in MECO T-14.

Q. How was the estimated average unamortized CIAC calculated for the test year?

A. The average unamortized CIAC for the test year was estimated by adding its beginning of the test year balance to the estimated CIAC additions for the test year, then subtracting the amortization of CIAC to determine the estimated end of the test year unamortized CIAC balance. The beginning of the test year balance and the end of the test year balance were then summed and divided by two to estimate the average unamortized CIAC balance for the test year.

Q. Did the Commission approve the deduction of CIAC from rate base in MECO's last rate case (1999 test year)?

A. Yes. The Commission included CIAC as a deduction from investments in assets funded by investors in determining rate base in the MECO 1999 Decision.

2) Customer Advances for Construction

Q. What is the test year estimate of customer advances for construction?

A. The estimated test year customer advances balance for construction is $4,271,000 for the Maui Division, as shown on MECO-1506, $249,000 for the Lanai Division, as shown on MECO-1512, and $154,000 for the Molokai Division, as shown on MECO-1518, for a total consolidated test year estimate of customer advances for construction of $4,673,000, as shown on MECO-1501.

Q. What are customer advances for construction?

A. Customer advances for construction are funds paid by customers to the Company which may be refunded in whole or in part as specified in the Company's tariff. Ms. Arase discusses customer advances for construction in detail in MECO T-14.

Q. How is the average customer advances for the test year calculated?

A. The average customer advances was calculated by taking the recorded customer advances balance at December 31, 2005 and adjusting for estimated changes in 2006 to determine the estimated balance at December 31, 2006. The process was then repeated for the 2007 test year. The sum of the balance at December 31, 2006 and 2007 divided by two is the estimated average test year balance for customer advances.

Q. Did the Commission approve the deduction of customer advances from rate base in MECO's last rate case (1999 test year)?

A. Yes. The Commission included customer advances as a deduction from investments in assets funded by investors in determining rate base in the MECO 1999 Decision.

3) Customer Deposits

Q. What is the test year estimate for customer deposits?

A. The estimated test year customer deposits balance is $3,601,000 for the Maui Division, as shown on MECO-1502, $95,000 for the Lanai Division, as shown on MECO-1508, and $187,000 for the Molokai Division, as shown on MECO-1514, for a total consolidated test year estimate for customer deposits of $3,883,000, as shown on MECO-1501.

Q. What are customer deposits?

A. Customer deposits are monies collected from customers who do not meet MECO's criteria for establishing credit at the time they request service. Ms. Suzuki discusses customer deposits in detail in MECO T-7.

Q. How is the average customer deposits calculated?

A. Ms. Suzuki explains the calculation of average customer deposits in MECO T-7.

Q. Did the Commission approve the deduction of customer deposits from funds from investors to determine rate base in MECO's last rate case (1999 test year)?

A. Yes. The Commission included customer deposits as a deduction from investments in assets funded by investors in determining rate base in the MECO 1999 Decision.

4) Accumulated Deferred Income Taxes

Q. What is the test year estimate of accumulated deferred income taxes?

A. The estimated test year accumulated deferred income taxes balance is $18,823,000 for the Maui Division, as shown on MECO-1502, $782,000 for the Lanai Division, as shown on MECO-1508, and $913,000 for the Molokai Division, as shown on MECO-1514, for a total consolidated test year estimate of accumulated deferred income taxes of $20,518,000, as shown on MECO-1501.

Q. What are accumulated deferred income taxes?

A. Accumulated deferred income taxes are the cumulative amount by which tax expense has exceeded tax remittances. This is primarily due to tax timing differences resulting from differences between book depreciation and accelerated depreciation used for the calculation of income taxes. Mr. Okada discusses accumulated deferred income taxes in detail in MECO T-13.

Q. How were the average accumulated deferred income taxes calculated?

A. Mr. Okada describes the calculation of average accumulated deferred income taxes in MECO T-13.

Q. Who provided accumulated deferred income tax funds?

A. Accumulated deferred income taxes are funds provided by ratepayers. Although rates are established based on income tax expense, tax remittances to the government on a cumulative basis have been lower than the taxes collected through rates. As a result, ratepayers have funded the accumulated deferred income tax balance. Over time, the Company will eventually pay to the government the amounts recorded as deferred income taxes.

Q. Did the Commission approve the deduction of accumulated deferred income taxes from rate base in MECO's last rate case (1999 test year)?

A. Yes. The Commission included accumulated deferred income taxes as a deduction from investments in assets funded by investors in determining rate base in the MECO 1999 Decision.

5) Unamortized Investment Tax Credits

Q. What is the test year estimate for unamortized investment tax credits?

A. The estimated test year unamortized investment tax credit balance is $10,279,000 for the Maui Division, as shown on MECO-1502, $428,000 for the Lanai Division, as shown on MECO-1508, and $499,000 for the Molokai Division, as shown on MECO-1514, for a total consolidated test year estimate for unamortized investment tax credits of $11,205,000, as shown on MECO-1501.

Q. What are unamortized investment tax credits?

A. Unamortized investment tax credits are tax credits which reduce tax payments in the year the credit originates, but for ratemaking purposes, the credits are amortized. Mr. Okada discusses unamortized investment tax credits in detail in MECO T-13.

Q. How was the average unamortized investment tax credit calculated?

A. Mr. Okada explains the calculation of average unamortized investment tax credits in MECO T-13.

Q. Who provides the unamortized investment tax credit funds?

A. Similar to accumulated deferred income taxes, unamortized investment tax credits are funds provided by ratepayers. These funds are provided as a result of differences in timing of when the credits are taken for purposes of calculating tax payments to the government as opposed to when adjustments are made to income tax expense for ratemaking purposes.

Q. Did the Commission approve the deduction of unamortized investment tax credits from rate base in MECO's last rate case (1999 test year)?

A. Yes. The Commission included unamortized investment tax credits as a deduction from investments in assets funded by investors in determining rate base in the MECO 1999 Decision.

SUMMARY

Q. What is your conclusion as to the rate base proposed by the Company?

A. The test year average rate base is $386,261,000 at present rates and $386,040,000 at proposed rates, as shown on MECO-1501. This rate base represents the investment which is used or useful in providing electric utility service that has been funded by investors. The investors should be allowed the opportunity to earn a fair rate of return on this rate base.

The Company has shown the reasonableness of each of the estimates used in this calculation and has demonstrated the appropriate treatment of each of the elements in the rate base calculation. Therefore, the rate base presented by the Company is reasonable and should be used in establishing the Company's electric rates in this docket.

Q. Does this conclude your testimony?

A. Yes, it does.

HAWAIIAN ELECTRIC COMPANY, INC.

GAYLE T. OHASHI

EDUCATIONAL BACKGROUND AND EXPERIENCE

Business Address:	900 Richards Street Honolulu, HI 96813
Current Position:	Director, Financial Analysis Division Management Accounting and Financial Services Department
Years of Service:	17 Years
Previous Positions with Current Employer:	Director, Internal Audit Division
Previous Experience:	Auditor, Coopers & Lybrand
Education:	University of Hawaii at Manoa Bachelor of Business Administration in Accounting
Certification:	Certified Public Accountant (inactive), State of Hawaii
Previous Testimonies:	Hawaiian Electric Company, Inc., Docket No. 2006-0386 Test Year 2007 Rate Case; Rate Base Hawaii Electric Light Company, Inc., Docket No. 05-0315 Test Year 2006 Rate Case; Rate Base Hawaiian Electric Company, Inc., Docket No. 04-0113 Test Year 2005 Rate Case; Rate Base Hawaii Electric Light Company, Inc., Docket No. 99-0207 Test Year 2000 Rate Case; Rate Base Hawaii Electric Light Company, Inc., Docket No. 97-0420 Test Year 1999 Rate Case; Rate Base Maui Electric Company, Limited, Docket No. 97-0346 Test Year 1999 Rate Case; Rate Base Hawaii Electric Light Company, Inc., Docket No. 94-0079

Purchase Power Contract Negotiations with Encogen, Hawaii, L.P.; Avoided Cost

Hawaii Electric Light Company, Inc., Docket No. 7956
Purchase Power Contract Negotiations with Kawaihae Cogeneration Partners; Avoided Cost

Maui Electric Company, Ltd.
Consolidated
2007 Average Rate Base
($ in thousands)

Investment in Assets Serving Customers	12/31/2006	12/31/2007	Average for 2007
Net Cost of Plant in Service	429,649	433,073	431,361
Property Held for Future Use	2,633	2,633	2,633
Fuel Inventory	15,811	15,811	15,811
Materials & Supplies Inventories	11,651	11,651	11,651
Unamortized Net SFAS 109 Regulatory Asset	9,010	8,826	8,918
Pension Asset	5,223	1,419	3,321
OPEB Amount	0	0	0
Unamortized System Development Costs	0	466	233
Working Cash at Present Rates	7,976	7,976	7,976
Total Investments in Assets	481,953	481,855	481,904
Funds from Non-Investors			
Unamortized CIAC	51,788	58,942	55,365
Customer Advances	4,480	4,865	4,673
Customer Deposits	3,600	4,165	3,883
Accumulated Deferred Income Taxes	21,460	19,576	20,518
Unamortized ITC	11,167	11,243	11,205
Total Deductions	92,495	98,791	95,643
Average Rate Base at Present Rates			386,261
Change in Working Cash			(221)
Average Rate Base at Proposed Rates			386,040

NOTE: Totals may not add exactly due to rounding.

Maui Electric Company, Ltd.
Maui Division
2007 Average Rate Base
($ in thousands)

Investment in Assets Serving Customers	12/31/2006	12/31/2007	Average for 2007	MECO Reference
Net Cost of Plant in Service	395,638	400,633	398,136	MECO-1503
Property Held for Future Use	2,633	2,633	2,633	MECO-1405
Fuel Inventory	14,629	14,629	14,629	MECO-408
Materials & Supplies Inventories	11,263	11,263	11,263	MECO-1504
Unamortized Net SFAS 109 Regulatory Asset	8,058	7,885	7,972	MECO-1306
Pension Asset	4,864	1,322	3,093	MECO-928
OPEB Amount	0	0	0	MECO-929
Unamortized System Development Costs	0	434	217	MECO-925
Working Cash at Present Rates	7,343	7,343	7,343	MECO-1507
Total Investments in Assets	444,428	446,142	445,285	
Funds from Non-Investors				
Unamortized CIAC	46,642	53,522	50,082	MECO-1505
Customer Advances	4,071	4,470	4,271	MECO-1506
Customer Deposits	3,339	3,863	3,601	MECO-WP-713
Accumulated Deferred Income Taxes	19,687	17,959	18,823	MECO-1305
Unamortized ITC	10,244	10,314	10,279	MECO-1304
Total Deductions	83,983	90,128	87,056	
Average Rate Base at Present Rates			358,230	
Change in Working Cash			(207)	MECO-1507
Average Rate Base at Proposed Rates			358,023	

NOTE: Totals may not add exactly due to rounding.

Maui Electric Company, Ltd.
Maui Division
Net Cost of Plant in Service
($ in thousands)

	Original Cost	Accum. Depreciation, Removal Reg. Liability, Acc. Retirement Oblig.	Net Plant In Service	MECO Reference
Recorded Balances - 12/31/05	616,573	(286,075)	330,498	
ESTIMATED CHANGES in 2006:				
Net Plant Additions	89,433		89,433	MECO-1401
Reclassify ICS System [1]	850		850	
Cost of Removal		1,205	1,205	MECO-1202
Salvage		(107)	(107)	MECO-1202
Depreciation Accrual		(25,606)	(25,606)	MECO-1202
Accumulated Deprec Transfer from Non-Utility Property		(635)	(635)	MECO-WP-1202
Retirements [2]	(1,022)	1,022	0	MECO-1404
Estimated Balances - 12/31/06	705,834	(310,196)	395,638	
ESTIMATED CHANGES in 2007:				
Net Plant Additions	32,984		32,984	MECO-1401
Cost of Removal		1,232	1,232	MECO-1202
Salvage		(54)	(54)	MECO-1202
Depreciation Accrual		(29,167)	(29,167)	MECO-1202
Retirements [2]	(1,018)	1,018	0	MECO-1404
Estimated Balances - 12/31/07	737,800	(337,167)	400,633	
AVERAGE 2007 BALANCE			**398,136**	

NOTE: Totals may not add exactly due to rounding.

[1] Represents the original cost of certain assets in the Interisland Communication System ("ICS") reclassified to utility property from non-utility property. While ICS is no longer being used, certain of the assets are now being utilized for utility purposes.

[2] Original cost of estimated retirements for the respective year.

Maui Electric Company, Ltd.
Maui Division
Materials & Supplies Inventory
($ in thousands)

	12/31/2006	12/31/2007	Average for 2007	MECO Reference
Production Inventory	8,326	8,326	8,326	MECO-508
Adjustment to Inventory related to Accounts Payable	(309)	(309)	(309)	MECO-WP-1504
Adjusted Production Inventory	8,017	8,017	8,017	(a)
Transmission & Distribution Inventory	3,654	3,654	3,654	MECO-618
Adjustment to Inventory related to Accounts Payable	(454)	(454)	(454)	MECO-WP-1504
Adjusted T&D Inventory	3,200	3,200	3,200	(b)
Lube Oil Inventory	129	129	129	MECO-509
Adjustment to Inventory related to Accounts Payable	(83)	(83)	(83)	MECO-WP-1504
Adjusted Lube Oil Inventory	46	46	46	(c)
Total Materials & Supplies	11,263	11,263	11,263	(a) + (b) + (c)

NOTE: Totals may not add exactly due to rounding.

Maui Electric Company, Ltd.
Maui Division
Unamortized Contributions In Aid of Construction
($ in thousands)

		MECO Reference
RECORDED BALANCES - 12/31/05	38,761	
ESTIMATED CHANGES in 2006:		
Cash Receipts	2,856	MECO-1406
In-Kind Receipts	6,769	MECO-1406
Transfer from Advances	119	MECO-1406
Amortization	(1,863)	MECO-WP-1204
ESTIMATED BALANCE - 12/31/06	46,642	
ESTIMATED CHANGES in 2007:		
Cash Receipts	1,915	MECO-1406
In-Kind Receipts	6,931	MECO-1406
Transfer from Advances	212	MECO-1406
Amortization	(2,178)	MECO-WP-1204
ESTIMATED BALANCE - 12/31/07	53,522	
AVERAGE 2007 BALANCE	50,082	

NOTE: Totals may not add exactly due to rounding.

Maui Electric Company, Ltd.
Maui Division
Customer Advances
($ in thousands)

		MECO Reference
RECORDED BALANCES - 12/31/05	4,569	
ESTIMATED CHANGES in 2006:		
Receipts	1,120	MECO-1407
Refunds	(1,499)	MECO-1407
Transfers to Contributions	(119)	MECO-1407
ESTIMATED BALANCE - 12/31/06	4,071	
ESTIMATED CHANGES in 2007:		
Receipts	1,198	MECO-1407
Refunds	(587)	MECO-1407
Transfers to Contributions	(212)	MECO-1407
ESTIMATED BALANCE - 12/31/07	4,470	
AVERAGE 2007 BALANCE	4,271	

NOTE: Totals may not add exactly due to rounding.

Maui Electric Company, Ltd.
Maui Division
WORKING CASH ITEMS, 2007
($ in thousands)

	(A) Revenue Collection Lag (Days)	Payment Lag Workpaper Reference	(B) Payment Lag (Days)	(C) Net Collection Lag (Days) (A) - (B)	Annual Amount Workpaper Reference	(D) Annual Amount	(E) Average Daily Amount - Present Rates (D) / 365	(F) Working Cash Required (Provided) under Present Rates (C) x (E)	(G) Average Daily Amount - Proposed Rates (D) / 365	(H) Working Cash Required (Provided) under Proposed Rates (C) x (G)
	per MECO-714	MECO WP-1507			MECO WP-2001					
ITEMS REQUIRING WORKING CASH:										
Fuel Purchases	36	p. 1	16	20	p.18	166,525	456	9,125	456	9,125
O&M Labor	36	p. 9	12	24	p.18	16,451	45	1,082	45	1,082
O&M Nonlabor	36	p. 23	32	4	p.18	28,809	79	316	79	316
ITEMS PROVIDING WORKING CASH:										
Purchased Power	36	p. 6	41	(5)	p.18	33,982	93	(466)	93	(466)
Revenue Taxes - Present Rates	36	p. 27	68	(32)	p.13	29,665	81	(2,601)		
Revenue Taxes - Proposed Rates	36	p. 27	68	(32)	p.13	31,237			86	(2,739)
Income Taxes - Present Rates	36	p. 30	40	(4)	p.16	10,305	28	(113)		
Income Taxes - Proposed Rates	36	p. 30	40	(4)	p.16	16,599			45	(182)
Total WORKING CASH								7,343		7,136
Change in WORKING CASH										(207)

Maui Electric Company, Ltd.
Lanai Division
2007 Average Rate Base
($ in thousands)

Investment in Assets Serving Customers	12/31/2006	12/31/2007	Average for 2007	MECO Reference
Net Cost of Plant in Service	15,623	14,750	15,187	MECO-1507
Property Held for Future Use	0	0	0	
Fuel Inventory	550	550	550	MECO-408
Materials & Supplies Inventories	193	193	193	MECO-1510
Unamortized Net SFAS 109 Regulatory Asset	424	434	429	MECO-1306
Pension Asset	141	38	90	MECO-928
OPEB Amount	0	0	0	MECO-929
Unamortized System Development Costs	0	13	7	MECO-925
Working Cash at Present Rates	338	338	338	MECO-1513
Total Investments in Assets	17,269	16,316	16,793	
Funds from Non-Investors				
Unamortized CIAC	1,989	1,976	1,983	MECO-1511
Customer Advances	225	272	249	MECO-1512
Customer Deposits	88	102	95	MECO-WP-713
Accumulated Deferred Income Taxes	818	746	782	MECO-1305
Unamortized ITC	426	429	428	MECO-1304
Total Deductions	3,546	3,525	3,536	
Average Rate Base at Present Rates			13,257	
Change in Working Cash			(6)	MECO-1513
Average Rate Base at Proposed Rates			13,251	

NOTE: Totals may not add exactly due to rounding.

Maui Electric Company, Ltd.
Lanai Division
Net Cost of Plant in Service
($ in thousands)

	Original Cost	Accum. Depreciation, Removal Reg. Liability, Acc. Retirement Oblig.	Net Plant In Service	MECO Reference
Recorded Balances - 12/31/05	29,260	(12,390)	16,870	
ESTIMATED CHANGES in 2006:				
Net Plant Additions	43		43	MECO-1401
Reclassify ICS System [1]	0		0	
Cost of Removal		53	53	MECO-1202
Salvage			0	
Depreciation Accrual		(1,343)	(1,343)	MECO-1202
Accumulated Deprec Transfer from Non-Utility Property	0	0	0	
Retirements [2]	(6)	6	0	MECO-1404
Estimated Balances - 12/31/06	29,297	(13,674)	15,623	
ESTIMATED CHANGES in 2007:				
Net Plant Additions	417		417	MECO-1401
Cost of Removal		54	54	MECO-1202
Salvage			0	
Depreciation Accrual		(1,344)	(1,344)	MECO-1202
Retirements [2]	(6)	6	0	MECO-1404
Estimated Balances - 12/31/07	29,708	(14,958)	14,750	
AVERAGE 2007 BALANCE			**15,187**	

NOTE: Totals may not add exactly due to rounding.

[1] Represents the original cost of certain assets in the Interisland Communication System ("ICS") reclassified to utility property from non-utility property. While ICS is no longer being used, certain of the assets are now being utilized for utility purposes.

[2] Original cost of estimated retirements for the respective year.

Maui Electric Company, Ltd.
Lanai Division
Materials & Supplies Inventory
($ in thousands)

	12/31/2006	12/31/2007	Average for 2007	MECO Reference
Production Inventory	127	127	127	MECO-508
Adjustment to Inventory related to Accounts Payable	(5)	(5)	(5)	MECO-WP-1510
Adjusted Production Inventory	122	122	122	(a)
Transmission & Distribution Inventory	78	78	78	MECO-618
Adjustment to Inventory related to Accounts Payable	(12)	(12)	(12)	MECO-WP-1510
Adjusted T&D Inventory	66	66	66	(b)
Lube Oil Inventory	9	9	9	MECO-509
Adjustment to Inventory related to Accounts Payable	(4)	(4)	(4)	MECO-WP-1510
Adjusted Lube Oil Inventory	5	5	5	(c)
Total Materials & Supplies	193	193	193	(a) + (b) + (c)

NOTE: Totals may not add exactly due to rounding.

Maui Electric Company, Ltd.
Lanai Division
Unamortized Contributions In Aid of Construction
($ in thousands)

		MECO Reference
RECORDED BALANCES - 12/31/05	1,986	
ESTIMATED CHANGES in 2006:		
Cash Receipts	37	MECO-1406
In-Kind Receipts	0	
Transfer from Advances	51	MECO-1406
Amortization	(85)	MECO-WP-1204
ESTIMATED BALANCE - 12/31/06	1,989	
ESTIMATED CHANGES in 2007:		
Cash Receipts	75	MECO-1406
In-Kind Receipts	0	
Transfer from Advances	0	
Amortization	(88)	MECO-WP-1204
ESTIMATED BALANCE - 12/31/07	1,976	
AVERAGE 2007 BALANCE	1,983	

NOTE: Totals may not add exactly due to rounding.

Maui Electric Company, Ltd.
Lanai Division
Customer Advances
($ in thousands)

		MECO Reference
RECORDED BALANCES - 12/31/05	409	
ESTIMATED CHANGES in 2006:		
Receipts	54	MECO-1407
Refunds	(187)	MECO-1407
Transfers to Contributions	(51)	MECO-1407
ESTIMATED BALANCE - 12/31/06	225	
ESTIMATED CHANGES in 2007:		
Receipts	59	MECO-1407
Refunds	(12)	MECO-1407
Transfers to Contributions		
ESTIMATED BALANCE - 12/31/07	272	
AVERAGE 2007 BALANCE	249	

NOTE: Totals may not add exactly due to rounding.

Maui Electric Company, Ltd.
Lanai Division
WORKING CASH ITEMS, 2007
($ in thousands)

	(A) Revenue Collection Lag (Days)	Payment Lag Workpaper Reference	(B) Payment Lag (Days)	(C) Net Collection Lag (Days) (A) - (B)	Annual Amount Workpaper Reference	(D) Annual Amount	(E) Average Daily Amount - Present Rates (D) / 365	(F) Working Cash Required (Provided) under Present Rates (C) x (E)	(G) Average Daily Amount - Proposed Rates (D) / 365	(H) Working Cash Required (Provided) under Proposed Rates (C) x (G)
	per MECO-714				MECO WP-2001					
ITEMS REQUIRING WORKING CASH:										
Fuel Purchases	36	MECO WP-1513 p. 1	15	21	p.30	6,173	17	355	17	355
O&M Labor	36	MECO WP-1507 p. 9	12	24	p.30	724	2	48	2	48
O&M Nonlabor	36	p. 23	32	4	p.30	1,152	3	13	3	13
ITEMS PROVIDING WORKING CASH:										
Revenue Taxes - Present Rates	36	MECO WP-1507 p. 27	68	(32)	p.25	896	2	(79)		
Revenue Taxes - Proposed Rates	36	p. 27	68	(32)	p.25	944			3	(83)
Income Taxes - Present Rates	36	p. 30	40	(4)	p.28	(126)	(0)	1		
Income Taxes - Proposed Rates	36	p. 30	40	(4)	p.28	65			0	(1)
Total WORKING CASH								338		332
Change in WORKING CASH										(6)

Maui Electric Company, Ltd.
Molokai Division
2007 Average Rate Base
($ in thousands)

Investment in Assets Serving Customers	12/31/2006	12/31/2007	Average for 2007	MECO Reference
Net Cost of Plant in Service	18,388	17,690	18,039	MECO-1511
Property Held for Future Use	0	0	0	
Fuel Inventory	632	632	632	MECO-408
Materials & Supplies Inventories	195	195	195	MECO-1516
Unamortized Net SFAS 109 Regulatory Asset	528	507	518	MECO-1306
Pension Asset	218	59	139	MECO-928
OPEB Amount	0	0	0	MECO-929
Unamortized System Development Costs	0	19	10	MECO-925
Working Cash at Present Rates	295	295	295	MECO-1519
Total Investments in Assets	20,256	19,397	19,827	
Funds from Non-Investors				
Unamortized CIAC	3,157	3,444	3,301	MECO-1517
Customer Advances	184	123	154	MECO-1518
Customer Deposits	173	200	187	MECO-WP-713
Accumulated Deferred Income Taxes	955	871	913	MECO-1305
Unamortized ITC	497	500	499	MECO-1304
Total Deductions	4,966	5,138	5,052	
Average Rate Base at Present Rates			14,775	
Change in Working Cash			(8)	MECO-1519
Average Rate Base at Proposed Rates			14,767	

NOTE: Totals may not add exactly due to rounding.

Maui Electric Company, Ltd.
Molokai Division
Net Cost of Plant in Service
($ in thousands)

	Original Cost	Accum. Depreciation, Removal Reg. Liability, Acc. Retirement Oblig.	Net Plant In Service	MECO Reference
Recorded Balances - 12/31/05	34,139	(14,407)	19,732	
ESTIMATED CHANGES in 2006:				
Net Plant Additions	53		53	MECO-1401
Reclassify ICS System [1]	0		0	
Cost of Removal		39	39	MECO-1202
Salvage			0	
Depreciation Accrual		(1,436)	(1,436)	MECO-1202
Accumulated Deprec Transfer from Non-Utility Property	0	0	0	
Retirements [2]	(11)	11	0	MECO-1404
Estimated Balances - 12/31/06	34,181	(15,793)	18,388	
ESTIMATED CHANGES in 2007:				
Net Plant Additions	474		474	MECO-1401
Cost of Removal		40	40	MECO-1202
Salvage		(4)	(4)	
Depreciation Accrual		(1,208)	(1,208)	MECO-1202
Retirements [2]	(44)	44	0	MECO-1404
Estimated Balances - 12/31/07	34,611	(16,921)	17,690	
AVERAGE 2007 BALANCE			**18,039**	

NOTE: Totals may not add exactly due to rounding.

[1] Original cost of estimated retirements for the respective year.

[1] Represents the original cost of certain assets in the Interisland Communication System ("ICS") reclassified to utility property from non-utility property. While ICS is no longer being used, certain of the assets are now being utilized for utility purposes.

[2] Original cost of estimated retirements for the respective year.

Maui Electric Company, Ltd.
Molokai Division
Materials & Supplies Inventory
($ in thousands)

	12/31/2006	12/31/2007	Average for 2007	MECO Reference
Production Inventory	43	43	43	MECO-508
Adjustment to Inventory related to Accounts Payable	(2)	(2)	(2)	MECO-WP-1516
Adjusted Production Inventory	41	41	41	(a)
Transmission & Distribution Inventory	179	179	179	MECO-618
Adjustment to Inventory related to Accounts Payable	(27)	(27)	(27)	MECO-WP-1516
Adjusted T&D Inventory	152	152	152	(b)
Lube Oil Inventory	9	9	9	MECO-509
Adjustment to Inventory related to Accounts Payable	(7)	(7)	(7)	MECO-WP-1516
Adjusted Lube Oil Inventory	2	2	2	(c)
Total Materials & Supplies	195	195	195	(a) + (b) + (c)

NOTE: Totals may not add exactly due to rounding.

Maui Electric Company, Ltd.
Molokai Division
Unamortized Contributions In Aid of Construction
($ in thousands)

		MECO Reference
RECORDED BALANCES - 12/31/05	2,674	
ESTIMATED CHANGES in 2006:		
Cash Receipts	20	MECO-1406
In-Kind Receipts	0	MECO-1406
Transfer from Advances	592	MECO-1406
Amortization	(129)	MECO-WP-1204
ESTIMATED BALANCE - 12/31/06	3,157	
ESTIMATED CHANGES in 2007:		
Cash Receipts	328	MECO-1406
In-Kind Receipts		
Transfer from Advances	108	MECO-1406
Amortization	(149)	MECO-WP-1204
ESTIMATED BALANCE - 12/31/07	3,444	
AVERAGE 2007 BALANCE	3,301	

NOTE: Totals may not add exactly due to rounding.

Maui Electric Company, Ltd.
Molokai Division
Customer Advances
($ in thousands)

		MECO Reference
RECORDED BALANCES - 12/31/05	790	
ESTIMATED CHANGES in 2006:		
Receipts	47	MECO-1407
Refunds	(61)	MECO-1407
Transfers to Contributions	(592)	MECO-1407
ESTIMATED BALANCE - 12/31/06	184	
ESTIMATED CHANGES in 2007:		
Receipts	50	MECO-1407
Refunds	(3)	MECO-1407
Transfers to Contributions	(108)	MECO-1407
ESTIMATED BALANCE - 12/31/07	123	
AVERAGE 2007 BALANCE	154	

NOTE: Totals may not add exactly due to rounding.

Maui Electric Company, Ltd.
Molokai Division
WORKING CASH ITEMS, 2007
($ in thousands)

	(A) Revenue Collection Lag (Days)	Payment Lag Workpaper Reference	(B) Payment Lag (Days)	(C) Net Collection Lag (Days) (A) - (B)	Annual Amount Workpaper Reference	(D) Annual Amount	(E) Average Daily Amount - Present Rates (D) / 365	(F) Working Cash Required (Provided) under Present Rates (C) x (E)	(G) Average Daily Amount - Proposed Rates (D) / 365	(H) Working Cash Required (Provided) under Proposed Rates (C) x (G)
	per MECO-714				MECO WP-2001					
ITEMS REQUIRING WORKING CASH:										
Fuel Purchases	36	MECO WP-1519 p. 1	20	16	p.42	7,247	20	318	20	318
O&M Labor	36	MECO WP-1507 p. 9	12	24	p.42	916	3	60	3	60
O&M Nonlabor	36	p. 23	32	4	p.42	1,661	5	18	5	18
ITEMS PROVIDING WORKING CASH:										
Revenue Taxes - Present Rates	36	MECO WP-1507 p. 27	68	(32)	p.37	1,129	3	(99)		
Revenue Taxes - Proposed Rates	36	p. 27	68	(32)	p.37	1,189			3	(104)
Income Taxes - Present Rates	36	p. 30	40	(4)	p.40	182	0	(2)		
Income Taxes - Proposed Rates	36	p. 30	40	(4)	p.40	423			1	(5)
Total WORKING CASH								295		287
Change in WORKING CASH										(8)

MECO T-16
DOCKET NO. 2006-0387

TESTIMONY OF

ROGER A. MORIN, Ph.D.

ON BEHALF OF

MAUI ELECTRIC COMPANY, LIMITED

Subject: Rate of Return on Common Equity

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MAUI ELECTRIC COMPANY, LIMITED

DIRECT TESTIMONY OF DR. ROGER A. MORIN

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INTRODUCTION AND SUMMARY

Q. Please state your name, address, and occupation.

A. My name is Dr. Roger A. Morin. My business address is Georgia State University, Robinson College of Business, University Plaza, Atlanta, Georgia, 30303. I am Emeritus Professor of Finance at the College of Business, Georgia State University and Professor of Finance for Regulated Industry at the Center for the Study of Regulated Industry at Georgia State University. I am also a principal in Utility Research International, an enterprise engaged in regulatory finance and economics consulting to business and government.

Q. Please describe your educational background.

A. I hold a Bachelor of Engineering degree and an MBA in Finance from McGill University, Montreal, Canada. I received my Ph.D. in Finance and Econometrics at the Wharton School of Finance, University of Pennsylvania.

Q. Please summarize your academic and business career.

A. I have taught at the Wharton School of Finance, University of Pennsylvania, Amos Tuck School of Business at Dartmouth College, Drexel University, University of Montreal, McGill University, and Georgia State University. I was a faculty member of Advanced Management Research International, and I am currently a faculty member of The Management Exchange Inc. and Exnet, Inc., where I continue to conduct frequent national executive-level education seminars throughout the United States and Canada. In the last twenty five years, I have conducted numerous national seminars on "Utility Finance," "Utility Cost of Capital," "Alternative Regulatory Frameworks," and on "Utility Capital Allocation," which I have developed on behalf of The Management Exchange Inc. and Exnet in conjunction with Public Utilities Reports, Inc.

I have authored or co-authored several books, monographs, and articles in academic scientific journals on the subject of finance. They have appeared in a variety of journals, including The Journal of Finance, The Journal of Business Administration, International Management Review, and Public Utility Fortnightly. I published a widely-used treatise on regulatory finance, Utilities' Cost of Capital, Public Utilities Reports, Inc., Arlington, Va. 1984. In late 1994, the same publisher released Regulatory Finance, a voluminous treatise on the application of finance to regulated utilities. A revised and expanded edition of this book, The New Regulatory Finance, has just been published. I have been engaged in extensive consulting activities on behalf of numerous corporations, legal firms, and regulatory bodies in matters of financial management and corporate litigation. MECO-1600 describes my professional credentials in more detail.

Q. Have you previously testified on cost of capital before utility regulatory commissions?

A. Yes, I have been a cost of capital witness before nearly fifty (50) regulatory bodies in North America, including the Hawaii Public Utilities Commission ("PUC" or "Commission"), the Federal Energy Regulatory Commission, and the Federal Communications Commission. I have also testified before the following state, provincial, and other local regulatory commissions:

Alabama	Florida	Missouri	Ontario
Alaska	Georgia	Montana	Oregon
Alberta	Hawaii	Nevada	Pennsylvania
Arizona	Illinois	New Brunswick	Quebec
Arkansas	Indiana	New Hampshire	South Carolina
British Columbia	Iowa	New Jersey	South Dakota
California	Kentucky	New York	Tennessee
City of New Orleans	Louisiana	Newfoundland	Texas
Colorado	Manitoba	North Carolina	Utah
CRTC	Maine	North Dakota	Vermont
Delaware	Maryland	Nova Scotia	Virginia
District of Columbia	Michigan	Ohio	Washington
FCC	Minnesota	Oklahoma	West Virginia
FERC	Mississippi		

The details of my participation in regulatory proceedings are provided in MECO-1600.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to present an independent appraisal of the fair and reasonable rate of return on the electric utility operations of the Maui Electric Company, Limited ("MECO," or "Company") in the State of Hawaii with particular emphasis on the fair return on the Company's common equity capital committed to that business. Based upon this appraisal, I have formed my professional judgment as to a return on such capital that would: (1) be fair to the ratepayer, (2) allow the Company to attract capital on reasonable terms, (3) maintain the Company's financial integrity, and (4) be comparable to returns offered on comparable risk investments. I will testify in this proceeding as to that opinion.

Q. Please briefly identify the exhibits accompanying your testimony.

A. I have attached to my testimony exhibits MECO-1600 through MECO-1609. These exhibits relate directly to points in my testimony, and are described in further detail in connection with the discussion of those points in my testimony.

Q. Please summarize your findings concerning MECO's cost of common equity.

A. In order to estimate a fair rate of return on MECO's common equity capital, I have employed the traditional methodologies which assume business-as-usual circumstances and then performed risk adjustments in order to account for MECO's higher than average risk circumstances by virtue of its small relative size. It is my opinion that a just and reasonable return on common equity ("ROE") for MECO is 11.25%.

My recommendation is derived from studies I performed using the Capital Asset Pricing Model ("CAPM"), Risk Premium, and Discounted Cash Flow ("DCF") methodologies. I performed two CAPM analyses, one using the CAPM and another using an empirical approximation of the CAPM ("ECAPM"). I performed two risk premium analyses: (1) a historical risk premium analysis on the electric utility industry, and (2) a study of the risk premiums reflected in ROEs allowed in the electric utility industry. I also performed DCF analyses on two surrogates for the Company's electric utility business. They are: a group of investment-grade integrated electric utilities that are representative of the electric utility industry and a group consisting of the companies that make up Moody's Electric Utility Index, also representative of the industry. The results from the various methodologies were adjusted to account for the above average risks faced by MECO relative to the industry.

My recommended ROE reflects the application of my professional judgment to the results in light of the indicated returns from my Risk Premium, CAPM, and DCF analyses. Moreover, my recommended return is predicated on the assumption that the Commission will approve: 1) the Company's capital structure for ratemaking purposes which is reflected on MECO-1701 and consists of approximately 55% common equity capital, and 2) the continuation of the Company's current energy cost adjustment clause in the same manner as in the past.

Q. Please explain how low allowed ROEs can increase both the future cost of equity and debt financing.

A. If a utility is authorized a ROE below the level required by equity investors, the utility will find it difficult to access the equity market through common stock issuance at its current market price. Investors will not provide equity capital at the current market price if the earnable return on equity is below the level they require given the risks of an equity investment in the utility. The equity market corrects this by generating a stock price in equilibrium that reflects the valuation of the potential earnings stream from an equity investment at the risk-adjusted return equity investors require. In the case of a utility that has been authorized a return below the level investors believe is appropriate for the risk they bear, the result is a decrease in the utility's market price per share of common stock. This reduces the financial viability of equity financing in two ways. First, because the utility's share price per common stock decreases, the net proceeds from issuing common stock are reduced. Second, since the utility's market to book ratio decreases with the decrease in the share price of common stock, the potential risk from dilution of equity investments reduces investors' inclination to purchase new issues of common stock. The ultimate effect is the utility will have to rely more on debt financing to meet its capital needs.

As the company relies more on debt financing, its capital structure becomes more leveraged. Because debt payments are a fixed financial obligation to the utility, and income available to common equity is subordinate to fixed charges, this decreases the operating income available for dividend and earnings growth. Consequently, equity investors face greater uncertainty about future dividends and earnings from the firm. As a result, the firm's equity becomes a riskier investment. The risk of default on the company's bonds also increases, making the utility's debt a riskier investment. This increases the cost to the utility from both debt and equity financing and increases the possibility the company will not have access to the capital markets for its outside financing needs. Ultimately, to ensure that MECO has access to capital markets for its capital needs, a fair and reasonable authorized rate of return on common equity capital of 11.25% is required.

Q. Please describe how your testimony is organized.

A. *The remainder of my testimony is divided into three (3) sections:*

(i) Regulatory Framework and Rate of Return;
(ii) Cost of Equity Estimates; and
(iii) Summary and Recommendation

The first section discusses the rudiments of rate of return regulation and the basic notions underlying rate of return. The second section contains the application of CAPM, Risk Premium, and DCF tests. In the third section, the results from the various approaches used in determining a fair return are summarized.

I. REGULATORY FRAMEWORK AND RATE OF RETURN

Q. What economic and financial concepts have guided your assessment of the Company's cost of common equity?

A. Two fundamental economic principles underlie the appraisal of the Company's cost of equity, one relating to the supply side of capital markets, the other to the demand side. According to the first principle, a rational investor is maximizing the performance of his portfolio only if he expects the returns earned on investments of comparable risk to be the same. If not, the rational investor will switch out of those investments yielding lower returns at a given risk level in favor of those investment activities offering higher returns for the same degree of risk. This principle implies that a company will be unable to attract the capital funds it needs to meet its service demands and to maintain financial integrity unless it can offer returns to capital suppliers that are comparable to those achieved on competing investments of similar risk. On the demand side, the second principle asserts that a company will continue to invest in real physical assets if the return on these investments exceeds or equals the company's cost of capital. This concept suggests that a regulatory commission should set rates at a level sufficient to create equality between the return on physical asset investments and the company's cost of capital.

Q. How does MECO's cost of capital relate to that of its parent company, Hawaiian Electric Company, Inc. ("HECO")?

A. I am treating MECO as a separate stand-alone entity, distinct from the parent company Hawaiian Electric Company, Inc. and its parent Hawaiian Electric Industries, Inc. ("HEI") because it is the cost of capital for MECO that we are attempting to measure and not the cost of capital for HECO or HEI's consolidated activities. Financial theory clearly establishes that the cost of equity is the risk-adjusted opportunity cost to the investor, in this case, HEI. The true cost of capital depends on the use to which the capital is put, in this case MECO's electric utility operations in the State of Hawaii. The specific source of funding an investment and the cost of funds to the investor are irrelevant considerations.

For example, if an individual investor borrows money at the bank at an after-tax cost of 8% and invests the funds in a speculative oil extraction venture, the required return on the investment is not the 8% cost but rather the return foregone in speculative projects of similar risk, say 20%. Similarly, the required return on MECO is the return foregone in comparable risk electricity utility operations, and is unrelated to the parent's cost of capital. The cost of capital is governed by the risk to which the capital is exposed and not by the source of funds. The identity of the shareholders has no bearing on the cost of equity.

Just as individual investors require different returns from different assets in managing their personal affairs, corporations should behave in the same manner. A parent company normally invests money in many operating companies of varying sizes and varying risks. These operating subsidiaries pay different rates for the use of investor capital, such as long-term debt capital, because investors recognize the differences in capital structure, risk, and prospects between subsidiaries. Therefore, the cost of investing funds in an operating utility subsidiary such as MECO is the return foregone on investments of similar risk and is unrelated to the identity of the investor.

Q. Please explain how a regulated company's rates should be set under traditional cost of service regulation.

A. Under the traditional regulatory process, a regulated company's rates should be set so that the company recovers its costs, including taxes and depreciation, plus a fair and reasonable return on its invested capital. The allowed rate of return must necessarily reflect the cost of the funds obtained, that is, investors' return requirements. In determining a company's rate of return, the starting point is investors' return requirements in financial markets. A rate of return can then be set at a level sufficient to enable the company to earn a return commensurate with the cost of those funds.

Funds can be obtained in two general forms, debt capital and equity capital. The cost of debt funds can be easily ascertained from an examination of the contractual interest payments. The cost of common equity funds, that is, investors' required rate of return, is more difficult to estimate. It is the purpose of the next section of my testimony to estimate MECO's cost of common equity capital.

Q. Dr. Morin, what must be considered in estimating a fair return on common equity?

A. The legal requirement is that the allowable ROE should be commensurate with returns on investments in other firms having corresponding risks. The allowed return should be sufficient to assure confidence in the financial integrity of the firm, in order to maintain creditworthiness, and ability to attract capital on reasonable terms. The attraction of capital standard focuses on investors' return requirements that are generally determined using market value methods, such as the Risk Premium, CAPM, or DCF methods. These market value tests define fair return as the return investors anticipate when they purchase equity shares of comparable risk in the financial marketplace. This is a market rate of return, defined in terms of anticipated dividends and capital gains as determined by expected changes in stock prices, and reflects the opportunity cost of capital. The economic basis for market value tests is that new capital will be attracted to a firm only if the return expected by the suppliers of funds is commensurate with that available from investments of comparable risk.

Q. What fundamental tenets underlie the determination of a fair and reasonable ROE?

A. The heart of utility regulation is the setting of just and reasonable rates by way of a fair and reasonable return. There are two landmark United States Supreme Court cases that define the legal principles underlying the regulation of a public utility's rate of return and provide the foundations for the notion of a fair return:

1. Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679 (1923).

2. Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 391 (1944).

The Bluefield case set the standard against which just and reasonable rates of return are measured:

> "*A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties ... The return should be reasonable, sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise money necessary for the proper discharge of its public duties.*" (Emphasis added)

The Hope case expanded on the guidelines to be used to assess the reasonableness of the allowed return. The Court reemphasized its statements in the Bluefield case and recognized that revenues must cover "capital costs." The Court stated:

> "*From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock ... By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital.*" (Emphasis added)

The United States Supreme Court reiterated the criteria set forth in Hope in Federal Power Commission v. Memphis Light, Gas & Water Division, 411 U.S. 458 (1973), in Permian Basin Rate Cases, 390 U.S. 747 (1968), and most recently in Duquesne Light Co. vs. Barasch, 488 U.S. 299 (1989). In the Permian cases, the Supreme Court stressed that a regulatory agency's rate of return order should:

> *"...reasonably be expected to maintain financial integrity, attract necessary capital, and fairly compensate investors for the risks they have assumed..."*

Therefore, the "end result" of this Commission's decision should be to allow MECO the opportunity to earn a ROE that is: (1) commensurate with returns on investments in other firms having corresponding risks, (2) sufficient to assure confidence in the company's financial integrity, and (3) sufficient to maintain the company's creditworthiness and ability to attract capital on reasonable terms.

Q. How is the fair rate of return determined?

A. The aggregate return required by investors is called the "cost of capital." The cost of capital is the opportunity cost, expressed in percentage terms, of the total pool of capital employed by the utility. It is the composite weighted cost of the various classes of capital (bonds, preferred stock, common stock) used by the utility, with the weights reflecting the proportions of the total capital that each class of capital represents. The fair return in dollars is obtained by multiplying the rate of return set by the regulator by the utility's "rate base." The rate base is essentially the net book value of the utility's plant and other assets used to provide utility service in a particular jurisdiction.

While utilities like MECO enjoy varying degrees of monopoly in the sale of public utility services, they must compete with everyone else in the free, open market for the input factors of production, whether labor, materials, machines, or capital. The prices of these inputs are set in the competitive marketplace by supply and demand, and it is these input prices that are incorporated in the cost of service computation. This is just as true for capital as for any other factor of production. Since utilities and other investor-owned businesses must go to the open capital market and sell their securities in competition with every other issuer, there is obviously a market price to pay for the capital they require, for example, the interest on debt capital, or the expected return on common and/or preferred equity.

Q. How does the concept of a fair return relate to the concept of opportunity cost?

A. The concept of a fair return is intimately related to the economic concept of "opportunity cost." When investors supply funds to a utility by buying its stocks or bonds, they are not only postponing consumption, giving up the alternative of spending their dollars in some other way, they also are exposing their funds to risk and forgoing returns from investing their money in alternative comparable-risk investments. The compensation they require is the price of capital. If there are differences in the risk of the investments, competition among firms for a limited supply of capital will bring different prices. These differences in risk are translated by the capital markets into price differences in much the same way that differences in the characteristics of commodities are reflected in different prices. The important point is that the prices of debt capital and equity capital are set by supply and demand, and both are influenced by the relationship between the risk and return expected for the respective securities and the risks expected from the overall menu of available securities.

Q. How does the Company obtain its capital and how is its overall cost of capital determined?

A. The funds employed by the Company are obtained in two general forms, debt capital and equity capital. The latter consists of preferred equity capital and common equity capital. The cost of debt funds and preferred stock funds can be ascertained easily from an examination of the contractual terms for the interest payments and preferred dividends. The cost of common equity funds, that is, equity investors' required rate of return, is more difficult to estimate because the dividend payments received from common stock are not contractual or guaranteed in nature. They are uneven and risky, unlike interest payments. Once a cost of common equity estimate has been developed, it can then easily be combined with the embedded cost of debt and preferred stock, based on the utility's capital structure, in order to arrive at the overall cost of capital.

Q. What is the market required rate of return on equity capital?

A. The market required rate of return on common equity, or cost of equity, is the return demanded by the equity investor. Investors establish the price for equity capital through their buying and selling decisions. Investors set return requirements according to their perception of the risks inherent in the investment, recognizing the opportunity cost of forgone investments, and the returns available from other investments of comparable risk.

II. COST OF EQUITY CAPITAL ESTIMATES

Q. Dr. Morin, how did you estimate the fair rate of return on common equity for MECO?

A. I employed three methodologies: (1) the CAPM, (2) the Risk Premium, and (3) the DCF methodologies. All three are market-based methodologies and are designed to estimate the return required by investors on the common equity capital committed to MECO. I have applied the aforementioned methodologies to samples of average risk utilities representative of the electric utility industry as a whole and adjusted the results upward to recognize MECO's higher relative risk.

Q. Why did you use more than one approach for estimating the cost of equity?

A. No one single method provides the necessary level of precision for determining a fair return, but each method provides useful evidence to facilitate the exercise of an informed judgment. Reliance on any single method or preset formula is inappropriate when dealing with investor expectations because of possible measurement difficulties and vagaries in individual companies' market data. Examples of such vagaries include dividend suspension, insufficient or unrepresentative historical data due a recent merger, impending merger or acquisition, and a new corporate identity due to restructuring activities. The advantage of using several different approaches is that the results of each one can be used to check the others.

As a general proposition, it is extremely dangerous to rely on only one generic methodology to estimate equity costs. The difficulty is compounded when only one variant of that methodology is employed. It is compounded even further when that one methodology is applied to a single company. Hence, several methodologies applied to several comparable risk companies should be employed to estimate the cost of common equity.

Q. Are there any difficulties in applying cost of capital methodologies in the current environment of changes in the electric utility industry?

A. Yes, there are. All the traditional cost of equity estimation methodologies are difficult to implement when you are dealing with the fast-changing circumstances of the electric utility industry. This is because utility company historical data have become less meaningful for an industry in a state of change. Past earnings and dividend trends are simply not indicative of the future. For example, historical growth rates of earnings and dividends have been depressed by eroding margins due to a variety of factors, including structural transformation, restructuring, and the transition to a more competitive environment. As a result, this historical data may not be representative of the future long-term earning power of these companies. Moreover, historical growth rates may not be representative of future trends for several electric utilities involved in mergers and acquisitions, as these companies going forward are not the same companies for which historical data are available.

Q. Dr. Morin, are you aware that some regulatory commissions and some analysts have placed principal reliance on DCF-based analyses to determine the cost of equity for public utilities?

A. Yes, I am.

Q. Do you agree with this approach?

A. While I agree that it is certainly appropriate to use the DCF methodology to estimate the cost of equity, there is no proof that the DCF produces a more accurate estimate of the cost of equity than other methodologies. As I have stated, there are three broad generic methodologies available to measure the cost of equity: DCF, Risk Premium, and CAPM. All three of these methodologies are accepted and used by the financial community and firmly supported in the financial literature.

When measuring the cost of common equity, which essentially deals with the measurement of investor expectations, no one single methodology provides a foolproof panacea. Each methodology requires the exercise of considerable judgment on the reasonableness of the assumptions underlying the methodology and on the reasonableness of the proxies used to validate the theory and apply the methodology. The failure of the traditional infinite growth DCF model to account for changes in relative market valuation, and the practical difficulties of specifying the expected growth component, are vivid examples of the potential shortcomings of the DCF model. It follows that more than one methodology should be employed in arriving at a judgment on the cost of equity and that all of these methodologies should be applied to multiple groups of comparable risk companies.

There is no single model that conclusively determines or estimates the expected return for an individual firm. Each methodology has its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Investors do not necessarily subscribe to any one method, nor does the stock price reflect the application of any one single method by the price-setting investor. Absent any hard evidence as to which method outperforms the other, all relevant evidence should be used, without discounting the value of any results, in order to minimize judgmental error, measurement error, and conceptual infirmities. A regulatory body should rely on the results of a variety of methods applied to a variety of comparable groups. There is no guarantee that a single DCF result is necessarily the ideal predictor of the stock price and of the cost of equity reflected in that price, just as there is no guarantee that a single CAPM or Risk Premium result constitutes the perfect explanation of a stock's price or the cost of equity.

Q. Does the financial literature support the use of more than a single method?

A. Yes, definitely. Authoritative financial literature strongly supports the use of multiple methods. For example, Professor Eugene F. Brigham, a widely respected scholar and finance academician, asserts:

In practical work, it is often best to use all three methods - CAPM, bond yield plus risk premium, and DCF - and then apply judgment when the methods produce different results. People experienced in estimating capital costs recognize that both careful analysis and some very fine judgments are required. It would be nice to pretend that these judgments are unnecessary and to specify an easy, precise way of determining the exact cost of equity capital. Unfortunately, this is not possible.[1]

In a subsequent edition of his best-selling corporate finance textbook, Dr. Brigham discusses the various methods used in estimating the cost of common equity capital, and states:

However, three methods can be used: (1) the Capital Asset Pricing Model (CAPM), (2) the discounted cash flow (DCF) model, and (3) the bond-yield-plus-risk-premium approach. These methods should not be regarded as mutually exclusive - no one dominates the others, and all are subject to error when used in practice. Therefore, when faced with the task of estimating a company' cost of equity, we generally use all three methods...[2]

Another prominent finance scholar, Professor Stewart Myers, in his best selling corporate finance textbook, points out:

The constant growth [DCF] formula and the capital asset pricing model are two different ways of getting a handle on the same problem.[3]

In an earlier article, Professor Myers explains:

Use more than one model when you can. Because estimating the opportunity cost of capital is difficult, only a fool throws away useful information. That means you should not use any one model or measure mechanically and exclusively. Beta is helpful as one tool in a kit, to be used in parallel with DCF models or other techniques for interpreting capital market data.[4]

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[1] E. F. Brigham and L. C. Gapenski, Financial Management Theory and Practice, p. 256 (4th ed., Dryden Press, Chicago, 1985)
[2] E. F. Brigham and L. C. Gapenski, Financial Management Theory and Practice, p. 348 (8th ed., Dryden Press, Chicago, 2005)
[3] R. A. Brealey and S. C. Myers, Principles of Corporate Finance, p. 182 (3rd ed., McGraw Hill, New York, 1988)
[4] S. C. Myers, "On the Use of Modern Portfolio Theory in Public Utility Rate Cases: Comment," Financial Management, p. 67 (Autumn 1978)

Q. Doesn't the wide use of the DCF methodology in past regulatory proceedings indicate that it is superior to other methods?

A. No, it does not. Uncritical acceptance of the standard DCF equation vests the model with a degree of infallibility that is not necessarily present. One of the leading experts on public utility regulation, Dr. Charles Phillips, discusses the dangers of relying solely on the DCF model:

> *[U]se of the DCF model for regulatory purposes involves both theoretical and practical difficulties. The theoretical issues include the assumption of a constant retention ratio (i.e. a fixed payout ratio) and the assumption that dividends will continue to grow at a rate 'g' in perpetuity. Neither of these assumptions has any validity, particularly in recent years. Further, the investors' capitalization rate and the cost of equity capital to a utility for application to book value (i.e. an original cost rate base) are identical only when market price is equal to book value. Indeed, DCF advocates assume that if the market price of a utility's common stock exceeds its book value, the allowable rate of return on common equity is too high and should be lowered; and vice versa. Many question the assumption that market price should equal book value, believing that "the earnings of utilities should be sufficiently high to achieve market-to-book ratios which are consistent with those prevailing for stocks of unregulated companies.*
>
> *...[T]here remains the circularity problem: Since regulation establishes a level of authorized earnings which, in turn, implicitly influences dividends per share, estimation of the growth rate from such data is an inherently circular process. For all of these reasons, the DCF model 'suggests a degree of precision which is in fact not present' and leaves 'wide room for controversy about the level of k [cost of equity]'.*[5]

Dr. Phillips also discusses the dangers of relying solely on the CAPM model because of the stringency of certain of its underlying assumptions, as is the case for any model in the social sciences.

Sole reliance on the DCF model simply ignores the capital market evidence and investors' use of other theoretical frameworks such as the Risk Premium and

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[5] C. F. Phillips, *The Regulation of Public Utilities Theory and Practice*, pp. 376-77. (Public Utilities Reports, Inc., 1988) pp. 376-77. [Footnotes omitted]

CAPM methodologies. The DCF model is only one of many tools to be employed to estimate the cost of equity. It is not a superior methodology which supplants other financial theory and market evidence. The same is true of the CAPM.

Q. Does the DCF model understate the cost of equity?

A. Yes, it does. Application of the DCF model produces estimates of common equity cost that are consistent with investors' expected return only when stock price and book value are reasonably similar, that is, when the Market-to-Book (M/B) ratio is close to unity. As shown below, application of the standard DCF model to utility stocks understates the investor's expected return when the M/B ratio of a given stock exceeds unity. This item is particularly relevant in the current capital market environment where utility stocks are trading at M/B ratios well above unity and have been for two decades. The converse is also true, that is, the DCF model overstates the investor's return when the stock's M/B ratio is less than unity. The reason for the distortion is that the DCF market return is applied to a book value rate base by the regulator, that is, a utility's earnings are limited to earnings on a book value rate base.

Q. Can you illustrate the effect of the M/B ratio on the DCF model by means of a simple example?

A. Yes. The simple numerical illustration shown in the table below demonstrates the result of applying a market value cost rate to book value rate base under three different M/B scenarios. The three columns correspond to three M/B situations: the stock trades below, equal to, and above book value, respectively. The last situation (boxed portion of the table) is noteworthy and representative of the current capital market environment. The DCF cost rate of 10%, made up of a 5% dividend yield and a 5% growth rate, is applied to the book value rate base of $50 to produce $5.00 of earnings. Of the $5.00 of earnings, the full $5.00 are required for dividends to produce a dividend yield of 5% on a stock price of $100.00, and no dollars are available for growth. The investor's return is therefore only 5% versus his required return of 10%. A DCF cost rate of 10%, which implies $10.00 of earnings, translates to only $5.00 of earnings on book value, a 5% return.

The situation is reversed in the first column when the stock trades below book value. The $5.00 of earnings are more than enough to satisfy the investor's dividend requirements of $1.25, leaving $3.75 for growth, for a total return of 20%. This item occurs when the DCF cost rate is applied to a book value rate base well above the market price.

Therefore, the DCF cost rate understates the investor's required return when stock prices are well above book, as is the case presently.

EFFECT OF MARKET-TO-BOOK RATIO ON MARKET RETURN

	Situation 1	*Situation 2*	*Situation 3*
1 Initial purchase price	$25.00	$50.00	$100.00
2 Initial book value	$50.00	$50.00	$ 50.00
3 **Initial M/B**	**0.50**	**1.00**	**2.00**
4 **DCF Return 10% = 5% + 5%**	**10.00%**	**10.00%**	**10.00%**
5 Dollar Return	$5.00	$5.00	$5.00
6 Dollar Dividends 5% Yield	$1.25	$2.50	$5.00
7 Dollar Growth 5% Growth	$3.75	$2.50	$0.00
8 ***Market Return***	**20.00%**	**10.00%**	**5.00%**

Q. Does the annual version of the DCF model understate the cost of equity?

A. Yes, it does. Another reason why the DCF methodology understates the cost of equity is that the annual DCF model usually employed in regulatory settings assumes that dividend payments are made annually at the end of the year, while most utilities in fact pay dividends on a quarterly basis. Failure to recognize the quarterly nature of dividend payments understates the cost of equity capital by about 30 basis points. By analogy, a bank rate on deposits which does not take into consideration the timing of the interest payments understates the true yield of your investment if you receive the interest payments more than once a year. Since the stock price employed in the DCF model already reflects the quarterly stream of dividends to be received, consistency therefore requires explicit recognition of the quarterly nature of dividend payments. One only has to think of what would happen to a company's stock price if the company was to suddenly announce that it is, from now on, paying dividends once a year at the end of the year instead of four times a year each quarter. Clearly, the stock price would decline by an amount reflecting the lost time value of money.

Q. Do regulators rely primarily on the DCF model?

A. No, I believe that a majority of regulatory commissions do not, as a matter of practice, rely solely on the DCF model results in setting the allowed rate of return on common equity. According to the results posted in a survey conducted by the National Association of Regulatory Utility Commissioners ("NARUC"), regulators utilize a variety of methods and rely on all the evidence submitted.

Q. Do regulators share your reservations on the reliability of the DCF model?

A. Yes, I believe they do. While a majority of regulatory commissions do not, as a matter of practice, rely solely on the DCF model results in setting the allowed rate of return on common equity, some regulatory commissions have explicitly recognized the need to avoid exclusive reliance upon the DCF model and have acknowledged the need to adjust the DCF result when M/B ratios exceed one[6].

My sentiments on the DCF model were echoed in a decision by the Indiana Utility Regulatory Commission (IURC). The IURC recognized its concerns with the DCF model and that the model understates the cost of equity. In Cause No. 39871 Final Order, the IURC states on page 24:

> *"....the DCF model, heavily relied upon by the Public, understates the cost of common equity. The Commission has recognized this fact before. In Indiana Mich. Power Co. (IURC 8/24/90), Cause No. 38728, 116 PUR4th 1, 17-18, we found:*
>
> *The unadjusted DCF result is almost always well below what any informed financial analyst would regard as defensible, and therefore requires an upward adjustment based largely on the expert witness's judgment."*

The Commission also expressed its concern with a witness relying solely on one methodology:

> *"......the Commission has had concerns in our past orders with a witness relying solely on one methodology in reaching an opinion on a proper return on equity figure." (page 25)*

Even more convincing is the fact that M/B ratios have exceeded unity for over two decades; this fact is clear evidence that regulators have in fact not relied on the DCF model exclusively. Had regulators relied exclusively on the DCF model, utility stocks would have traded at or near book value. Regulators have "corrected" for this chronic M/B problem by considering alternative methods for estimating capital cost.

Q. Is the usage of the DCF model prevalent in corporate practices?

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[6] See the Indiana Utility Regulatory Commission decision in Indiana Mich. Power Co. (IURC 8/24/90), Cause No. 38728, 116 PUR4th 1, 17-18. See also the Iowa Utilities Board decision in U.S. West Communications, Inc., Docket No., RPR-93-9, 152 PUR4th 459. See also the Hawaii Public Utilities Commission decision in Hawaiian Electric Company, Inc., Docket No. 6998, PUR4th 134. More recently, see the Pennsylvania Public Utility Commission decision in Pennsylvania-American Water Company, Docket 130680, PUR4th, 1/25/02.

A. No, not really. The CAPM continues to be widely used by analysts, investors, and corporations. Bruner, Eades, Harris, and Higgins (1998) in a comprehensive survey[7] of current practices for estimating the cost of capital found that 81% of companies used the CAPM to estimate the cost of equity, 4% used a modified CAPM, and 15% were uncertain. In another comprehensive survey conducted by Graham and Harvey (2001), the managers surveyed reported using more than one methodology to estimate the cost of equity, and 73% used the CAPM.[8] Since its introduction by Professor William F. Sharpe in 1964, the CAPM has gained immense popularity as the practitioner's method of choice when estimating cost of capital under conditions of risk.[9] The intuitive simplicity of its basic concept (that investors must get compensated for the risk they assume), and the relatively easy application of the CAPM are the main reasons behind its popularity.

Q. Do the assumptions underlying the DCF model require that the model be treated with caution?

A. Yes, particularly in today's rapidly changing electric utility industry. Even ignoring the fundamental thesis that several methods and/or variants of such methods should be used in measuring equity costs, the DCF methodology, as those familiar with the industry and the accepted norms for estimating the cost of equity are aware, is problematic for use in estimating cost of equity at this time.

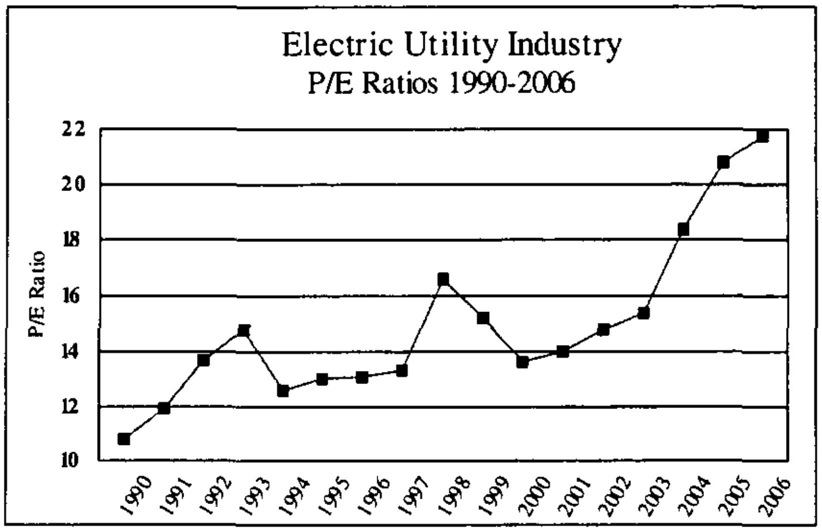
Several fundamental structural changes have transformed the electric utility industry since the standard DCF model and its assumptions were developed. For example, deregulation, increased wholesale competition triggered by national

[7]Bruner, R. F., Eades, K. M., Harris, R. S., and Higgins, R. C., "Best Practices in Estimating the Cost of Capital: Survey and Synthesis," *Financial Practice and Education*, Vol. 8, Number 1, Spring/Summer 1998, page 18.
[8]Graham, J. R. and Harvey, C. R., "The Theory and Practice of Corporate Finance: Evidence from the Field," *Journal of Financial Economics*, Vol. 61, 2001, pp. 187-243.
[9] See practitioner surveys by Graham & Harvey (2001) and Bruner, et. al. (1988)

policy, changes in customer attitudes regarding utility services, the evolution of alternative energy sources, highly volatile fuel prices, and mergers-acquisitions have all influenced stock prices in ways that have deviated substantially from the assumptions of the DCF model. These changes suggest that some of the fundamental assumptions underlying the standard DCF model, particularly that of constant growth and constant relative market valuation, for example price/earnings (P/E) ratios and M/B ratios, are problematic at this point in time for utility stocks, and that, therefore, alternate methodologies to estimate the cost of common equity should be accorded at least as much weight as the DCF method.

Q. Is the constant relative market valuation assumption inherent in the DCF model always reasonable?

A. No, not always. Caution must be exercised when implementing the standard DCF model in a mechanistic fashion, for it may fail to recognize changes in relative market valuations over time. The traditional DCF model is not equipped to deal with surges in M/B and P/E ratios. The standard DCF model assumes a constant market valuation multiple, that is, a constant P/E ratio and a constant M/B ratio. Stated another way, the model assumes that investors expect the ratio of market price to dividends (or earnings) in any given year to be the same as the current ratio of market price to dividend (or earnings), and that the stock price will grow at the same rate as the book value. This item is a necessary result of the infinite growth assumption. This assumption is unrealistic under current conditions as the graph below clearly demonstrates. The DCF model is not equipped to deal with sudden surges in M/B and P/E ratios, as was experienced by utility stocks in recent years.



Q. What is your recommendation given such market conditions?

A. Caution and judgment are required in interpreting the results of the standard DCF model because of: (1) the effect of changes in risk and growth on electric utilities, (2) the fragile applicability of the DCF model to utility stocks in the current capital market environment, and (3) the practical difficulties associated with the growth component of the standard DCF model. Hence, there is a clear need to go beyond the standard DCF results and take into account the results produced by alternate methodologies in arriving at a common equity recommendation.

Q. Do the assumptions underlying the CAPM require that the model be treated with caution?

A. Yes, as was the case with the DCF model, the assumptions underlying any model in the social sciences, including the CAPM, are stringent. Moreover, the empirical validity of the CAPM has been the subject of intense research in recent years. Although the CAPM provides useful evidence, it must be complemented by other methodologies as well.

Q. Are the assumptions underlying the CAPM any more or less confining than those underlying the DCF model?

A. I believe that the assumptions underlying the CAPM are less stringent than those underlying the DCF theory. This becomes apparent if we view the CAPM as a special case of the Arbitrage Pricing Model (APM), where the market portfolio is the only factor affecting security prices. The assumptions underlying the APM are far less stringent than the assumptions required for the DCF model to obtain. The APM derives from only two major reasonable assumptions: (1) that security returns are linear functions of several economic factors, and (2) that no profitable arbitrage opportunities exist since investors are able to eliminate such opportunities through risk-free arbitrage transactions. The other assumptions required by the APM are that investors are greedy and risk averse, that they can diversify company-specific risks by holding large portfolios, and that enough investors possess similar expectations to trigger the arbitrage process.

As a tool in the regulatory arena, the CAPM is a rigorous conceptual framework, and is logical insofar as it is not subject to circularity problems, since its inputs are objective, market-based quantities, largely immune to regulatory decisions. The data requirements of the model are not prohibitive. The CAPM is one of several tools in the arsenal of techniques to determine the cost of equity capital. Caution, appropriate training in finance and econometrics, and judgment are required for its successful execution, as is the case with the DCF and Risk Premium methodologies.

Q. Dr. Morin, please provide an overview of your risk premium analyses.

A. In order to quantify the risk premium for MECO, I have performed four risk premium studies. The first two studies deal with aggregate stock market risk premium evidence using two versions of the CAPM methodology and the other two studies deal directly with the electric utility industry.

A. <u>CAPM Estimates</u>

Q. Please describe your application of the CAPM risk premium approach.

A. My first two risk premium estimates are based on the CAPM and on an empirical approximation to the CAPM (ECAPM). The CAPM is a fundamental paradigm of finance. Simply put, the fundamental idea underlying the CAPM is that risk-averse investors demand higher returns for assuming additional risk, and higher-risk securities are priced to yield higher expected returns than lower-risk securities. The CAPM quantifies the additional return, or risk premium, required for bearing incremental risk. It provides a formal risk-return relationship anchored on the basic idea that only market risk matters, as measured by beta. According to the CAPM, securities are priced such that their:

EXPECTED RETURN = RISK-FREE RATE + RISK PREMIUM

Denoting the risk-free rate by R_F and the return on the market as a whole by R_M, the CAPM is stated as follows:

$$K = R_F + \beta(R_M - R_F)$$

This is the seminal CAPM expression, which states that the return required by investors is made up of a risk-free component, R_F, plus a risk premium determined by $\beta(R_M - R_F)$. To derive the CAPM risk premium estimate, three quantities are required: the risk-free rate (R_F), beta (β), and the market risk premium, ($R_M - R_F$). In order to estimate the CAPM return for the average risk electric utility, I used a risk-free rate of 4.9%, a beta estimate of 0.86 and a market risk premium estimate of 7.4%. These respective inputs to the CAPM are explained below.

Q. What risk-free rate did you use in your CAPM and risk premium analyses?

A. To implement the CAPM and Risk Premium methods, an estimate of the risk-free return is required as a benchmark. As a proxy for the risk-free rate, I have relied on the current level of 30-year Treasury bond yields.

The appropriate proxy for the risk-free rate in the CAPM is the return on the longest term Treasury bond possible. This is because common stocks are very long-term instruments more akin to very long-term bonds rather than to short-term or intermediate-term Treasury notes. In a risk premium model, the ideal estimate for the risk-free rate has a term to maturity equal to the security being analyzed. Since common stock is a very long-term investment because the cash flows to investors in the form of dividends last indefinitely, the yield on the longest-term possible government bonds, that is the yield on 30-year Treasury bonds, is the best measure of the risk-free rate for use in the CAPM. The expected common stock return is based on very long-term cash flows, regardless of an individual's holding time period. Moreover, utility asset investments generally have very long-term useful lives and should correspondingly be matched with very long-term maturity financing instruments.

While long-term Treasury bonds are potentially subject to interest rate risk, this is only true if the bonds are sold prior to maturity. A substantial fraction of bond market participants, usually institutional investors with long-term liabilities (pension funds, insurance companies), in fact hold bonds until they mature, and therefore are not subject to interest rate risk. Moreover, institutional bondholders neutralize the impact of interest rate changes by matching the maturity of a bond portfolio with the investment planning period, or by engaging in hedging transactions in the financial futures markets. The merits and mechanics of such immunization strategies are well documented by both academicians and practitioners.

Another reason for utilizing the longest maturity Treasury bond possible is that common equity has an infinite life span, and the inflation expectations embodied in its market-required rate of return will therefore be equal to the inflation rate anticipated to prevail over the very long-term. The same expectation should be embodied in the risk free rate used in applying the CAPM model. It stands to reason that the yields on 30-year Treasury bonds will more closely incorporate within their yield the inflation expectations that influence the prices of common stocks than do short-term or intermediate-term U.S. Treasury notes.

Among U.S. Treasury securities, 30-year Treasury bonds have the longest term to maturity and the yield on such securities should be used as proxies for the risk-free rate in applying the CAPM, provided there are no anomalous conditions existing in the 30-year Treasury market. In the absence of such conditions, I have relied on the yield on 30-year Treasury bonds in implementing the CAPM and risk premium methods.

Q. Dr. Morin, why did you reject short-term interest rates as proxies for the risk-free rate in implementing the CAPM?

A. Short-term rates are volatile, fluctuate widely, and are subject to more random disturbances than are long-term rates. Short-term rates are largely administered rates. For example, Treasury bills are used by the Federal Reserve as a policy vehicle to stimulate the economy and to control the money supply, and are used by foreign governments, companies, and individuals as a temporary safe-house for money.

As a practical matter, it makes no sense to match the return on common stock to the yield on 90-day Treasury Bills. This is because short-term rates, such as the yield on 90-day Treasury Bills, fluctuate widely, leading to volatile and unreliable equity return estimates. Moreover, yields on 90-day Treasury Bills typically do not match the equity investor's planning horizon. Equity investors generally have an investment horizon far in excess of 90 days.

As a conceptual matter, short-term Treasury Bill yields reflect the impact of factors different from those influencing the yields on long-term securities such as common stock. For example, the premium for expected inflation embedded into 90-day Treasury Bills is likely to be far different than the inflationary premium embedded into long-term securities yields. On grounds of stability and consistency, the yields on long-term Treasury bonds match more closely with common stock returns.

Q. What is the current level of U.S. Treasury 30-year bonds?

A. The yield on U.S. Treasury 30-year bonds prevailing in October 2006, as reported in Bloomberg.com and Value Line, was 4.9%. Accordingly, I use 4.9% as my estimate of the risk-free rate component of the CAPM.

Q. How did you select the beta for your CAPM analysis?

A. A major thrust of modern financial theory as embodied in the CAPM is that perfectly diversified investors can eliminate the company-specific component of risk, and that only market risk remains. The latter is technically known as "beta", or "systematic risk". The beta coefficient measures change in a security's return relative to that of the market. The beta coefficient states the extent and direction of movement in the rate of return on a stock relative to the movement in the rate of return on the market as a whole. It indicates the change in the rate of return on a stock associated with a one percentage point change in the rate of return on the market, and thus measures the degree to which a particular stock shares the risk of the market as a whole. Modern financial theory has established that beta incorporates several economic characteristics of a corporation which are reflected in investors' return requirements.

As a proxy for the beta of the electric utility industry, I examined the betas of a sample of widely-traded investment-grade electric utilities covered by Value Line. This group is examined in more detail later in my testimony, in connection with the DCF estimates of the cost of common equity. As displayed on page 1 of Exhibit MECO-1601, the average beta for the group is currently 0.86. I also examined the average beta of the companies that make up Moody's Electric Utility Index as a proxy for the electric utility industry. As shown on page 2 of Exhibit MECO-1601, the average beta of the Moody's group is 0.92. Of course, to the extent that MECO is riskier than average, the beta applicable to MECO is correspondingly higher.

Based on these results, I shall use 0.86 as my estimate for the beta applicable to the average risk electric utility. I reiterate that to the extent that MECO is riskier than average, the beta applicable to MECO is correspondingly higher.

Q. What market risk premium ("MRP") estimate did you use in your CAPM analysis?

A. For the MRP, I used 7.4%. This estimate was based on the results of both forward-looking and historical studies of long-term risk premiums. First, the Ibbotson Associates study, Stocks, Bonds, Bills, and Inflation, 2006 Yearbook, compiling historical returns from 1926 to 2005, shows that a broad market sample of common stocks outperformed long-term U. S. Treasury bonds by 6.5%. The historical MRP over the income component of long-term Treasury bonds rather than over the total return is 7.1%. Ibbotson Associates recommend the use of the latter as a more reliable estimate of the historical MRP, and I concur with this viewpoint. The historical MRP should be computed using the income component of bond returns because the intent, even using historical data, is to identify an expected MRP. The more accurate way to estimate the MRP from historic data is to use the <u>income</u> return, not <u>total</u> returns on government bonds, as explained at page 66 of <u>Ibbotson Associates, Stocks, Bonds, Bills, and Inflation: Valuation Edition, 2005 Yearbook</u>. This is because the income component of total bond return (*i.e.* the coupon rate) is a far better estimate of expected return than the total return (*i.e.* the coupon rate + capital gain), as realized capital gains/losses are largely unanticipated by bond investors. The long-horizon (1926-2005) MRP (based on income returns, as required) is specifically calculated to be 7.1% rather than 6.5%.

Second, a DCF analysis applied to the aggregate equity market using Value Line's aggregate stock market index and growth forecasts indicates a prospective MRP of 7.8%. The average of the historical (7.1%) and prospective estimates (7.8%), which is 7.4%, provides a reasonable estimate of the MRP.

Q. On what maturity bond does the Ibbotson historical risk premium data rely on?

A. Because 30-year bonds were not always traded or even available throughout the entire 1926-2005 long period covered in the Ibbotson Associate Study of historical returns, the latter study relied on bond return data based on 20-year Treasury bonds. To the extent that the normal yield curve is virtually flat above maturities of 20 years over most of the period covered in the Ibbotson study, the difference in yield is not material. In fact, the difference in yield between 30-year and 20-year bonds is actually negative. The average difference in yield over the 1977-2006 period is 13 basis points, that is, the yield on 20-year bonds is slightly higher than the yield on 30-year bonds.

Q. Why did you use long time periods in arriving at your historical MRP estimate?

A. Because realized returns can be substantially different from prospective returns anticipated by investors when measured over short time periods, it is important to employ returns realized over long time periods rather than returns realized over more recent time periods when estimating the MRP with historical returns. Therefore, a risk premium study should consider the longest possible period for which data are available. Short-run periods during which investors earned a lower risk premium than they expected are offset by short-run periods during which investors earned a higher risk premium than they expected. Only over long time periods will investor return expectations and realizations converge.

I have therefore ignored realized risk premiums measured over short time periods, since they are heavily dependent on short-term market movements. Instead, I relied on results over periods of enough length to smooth out short-term aberrations, and to encompass several business and interest rate cycles. The use of the entire study period in estimating the appropriate MRP minimizes subjective judgment and encompasses many diverse regimes of inflation, interest rate cycles, and economic cycles.

To the extent that the estimated historical equity risk premium follows what is known in statistics as a random walk, the best estimate of the future risk premium is the historical mean. Since I found no evidence that the MRP in common stocks has changed over time, that is, no significant serial correlation in the Ibbotson study, it is reasonable to assume that these quantities will remain stable in the future.

Q. Please describe your prospective approach in deriving the MRP in the CAPM analysis.

A. For my prospective estimate of the MRP, I applied a DCF analysis to the aggregate equity market using Value Line's VLIA software. The dividend yield on the dividend-paying stocks that make up the Value Line Composite index made up of some 1800 stocks is currently 1.20% (VLIA 10/2006 edition), and the average projected dividend growth rate is 11.2%. Adding the dividend yield to the growth component produces an expected return on the aggregate equity market of 12.4%. Following the tenets of the DCF model, the spot dividend yield must be converted into an expected dividend yield by multiplying it by one plus the growth rate. This brings the expected return on the aggregate equity market to 12.5%. Recognition of the quarterly timing of dividend payments rather than the annual timing of dividends assumed in the annual DCF model brings the MRP estimate to approximately 12.7%. Subtracting the risk-free rate of 4.9% from the latter, the implied risk premium is 7.8% over long-term U.S. Treasury bonds. The average of the historical (7.1%) and prospective MRP (7.8%) estimate is 7.4%.

As a check on my MRP estimate, I examined a recent 2003 comprehensive article published in Financial Management, Harris, Marston, Mishra, and O'Brien ("HMMO") that provides estimates of the ex ante expected returns for S&P 500 companies over the period 1983-1998[10]. HMMO measure the expected rate of return (cost of equity) of each dividend-paying stock in the S&P 500 for each

[10] Harris, R. S., Marston, F. C., Mishra, D. R., and O'Brien, T. J., "*Ex Ante* Cost of Equity Estimates of S&P 500 Firms: The Choice Between Global and Domestic CAPM," Financial Management, Autumn 2003, pp. 51-66.

month from January 1983 to August 1998 by using the constant growth DCF model. The prevailing risk-free rate for each year was then subtracted from the expected rate of return for the overall market to arrive at the MRP for that year. The table below, drawn from HMMO Table 2, displays the average prospective risk premium estimate for each year from 1983 to 1998. The average MRP estimate for the overall period is 7.2%, which is close to my estimate of 7.4%.

Market Risk Premium Estimates

Year	DCF Market Risk Premium
1983	6.6%
1984	5.3%
1985	5.7%
1986	7.4%
1987	6.1%
1988	6.4%
1989	6.6%
1990	7.1%
1991	7.5%
1992	7.8%
1993	8.2%
1994	7.3%
1995	7.7%
1996	7.8%
1997	8.2%
1998	9.2%
MEAN	7.2%

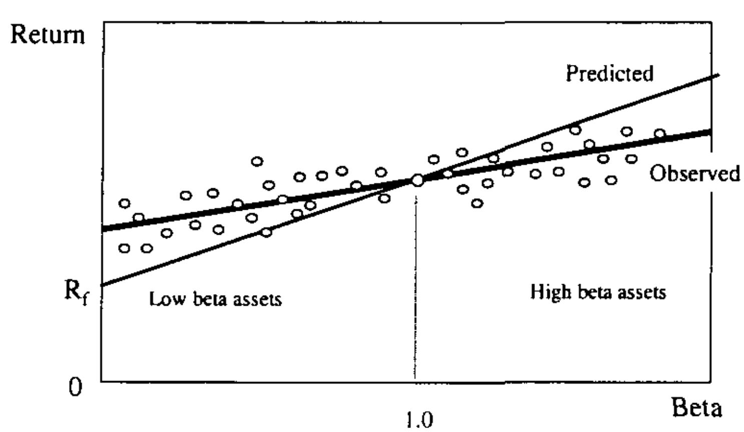
Q. What is your risk premium estimate of the company's cost of equity using the CAPM approach?

A. Inserting those input values in the CAPM equation, namely a risk-free rate of 4.9%, a beta of 0.86, and a MRP of 7.4%, the CAPM estimate of the cost of common equity for MECO is: 4.9% + 0.86 x 7.4% = 11.3%. This estimate becomes 11.6% with flotation costs, discussed later in my testimony.

Q. What is your risk premium estimate using the empirical version of the CAPM?

A. There have been countless empirical tests of the CAPM in the finance literature in order to determine to what extent security returns and betas are related in the manner predicted by the CAPM. This literature is summarized in Chapter 13 of my 1994 book, Regulatory Finance, and Chapter 6 of my latest book, The New Regulatory Finance, both published by Public Utilities Report Inc. The results of the tests support the idea that beta is related to security returns, that the risk-return tradeoff is positive, and that the relationship is linear. The contradictory finding is that the risk-return tradeoff is not as steeply sloped as the predicted CAPM. That is, empirical research has long shown that low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. A CAPM-based estimate of cost of capital underestimates the return required from low-beta securities and overstates the return required from high-beta securities, based on the empirical evidence. This is one of the most well-known results in finance, and it is displayed graphically below.

CAPM: Predicted vs Observed Returns



A number of variations on the original CAPM theory have been proposed to explain this finding. The empirical version of the CAPM ("ECAPM") makes use of these empirical findings. The ECAPM estimates the cost of capital with the equation:

$$K = R_F + \acute{\alpha} + \beta \times (MRP - \acute{\alpha})$$

where $\acute{\alpha}$ is the "alpha" of the risk-return line, a constant, MRP is the market risk premium ($R_M - R_F$), and the other symbols are defined as usual. Inserting the long-term risk-free rate as a proxy for the risk-free rate, an alpha in the range of 1% - 2%, and reasonable values of beta and the MRP in the above equation produces results that are indistinguishable from the following more tractable ECAPM expression:

$$K = R_F + 0.25(R_M - R_F) + 0.75\beta(R_M - R_F)$$

An alpha range of 1% - 2% is somewhat lower than that estimated empirically. The use of a lower value for alpha leads to a lower estimate of the cost of capital for low-beta stocks such as regulated utilities. This is because the use of a long-term risk-free rate rather than a short-term risk-free rate already incorporates some of the desired effect of using the ECAPM. That is, the long-term risk-free rate version of the CAPM has a higher intercept and a flatter slope than the short-term risk-free version which has been tested. This is also because the use of adjusted betas rather than the use of raw betas also incorporates some of the desired effect of using the ECAPM. Thus, it is reasonable to apply a conservative alpha adjustment.

Q. Is the use of the ECAPM consistent with the use of adjusted betas?

A. Yes, it is. Some have argued that the use of the ECAPM is inconsistent with the use of adjusted betas, such as those supplied by Value Line, Bloomberg, and Ibbotson

Associates. This is because the reason for using the ECAPM is to allow for the tendency of betas to regress toward the mean value of 1.00 over time, and, since Value Line betas are already adjusted for such trend, an ECAPM analysis results in double-counting. This argument is erroneous. Fundamentally, the ECAPM is not an adjustment, increase or decrease, in beta. This is obvious from the fact that the observed return on high beta securities is actually lower than that produced by the CAPM estimate. The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence. The ECAPM and the use of adjusted betas comprised two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks. Even if the ECAPM is used, the return for low-beta securities is understated if the betas are understated. Referring back to the previous graph, the ECAPM is a return (vertical axis) adjustment and not a beta (horizontal axis) adjustment. Both adjustments are necessary. Moreover, the use of adjusted betas compensates for interest rate sensitivity of utility stocks not captured by unadjusted betas.

Exhibit MECO-1608 contains a full discussion of the ECAPM, including its theoretical and empirical underpinnings. In short, the following equation provides a viable approximation to the observed relationship between risk and return, and provides the following cost of equity capital estimate:

$$K = R_F + 0.25\,(R_M - R_F) + 0.75\ \beta\,(R_M - R_F)$$

Inserting 4.9% for the risk-free rate R_F, a MRP of 7.4% for $(R_M - R_F)$ and a beta of 0.86 in the above equation, the return on common equity is 11.5% without flotation costs and 11.8% with flotation costs.

Q. Dr. Morin, please summarize your CAPM estimates.

A. The table below summarizes the common equity estimates obtained from my CAPM studies. The average CAPM result is 11.7%.

CAPM

	%ROE
CAPM	11.6%
Empirical CAPM	11.8%
AVERAGE	11.7%

B. Risk Premium Estimates

Q. Please describe your historical risk premium analysis of the electric utility industry.

A. As a proxy for the risk premium applicable to the electric utility industry, I estimated the historical risk premium for the electric utility industry with an annual time series analysis applied to the industry as a whole, using *Moody's Electric Utility Index* as an industry proxy. The analysis is depicted on Exhibit MECO-1602. The risk premium was estimated by computing the actual return on equity capital for Moody's Index for each year, using the actual stock prices and dividends of the index, and then subtracting the long-term government bond return for that year. Data for this particular index was unavailable beyond 2002 following the acquisition of Moody's by Mergent. The study was updated to 2006 using S&P's Electric Utility Index data.

As shown on Exhibit MECO-1602, the average risk premium over the period was 5.5% over long-term Treasury bond historical returns and 5.6% over the income component (yield) of long-term Treasury bond. Given that the risk-free rate is 4.9%, the implied cost of equity for the average electric utility from this particular method is 4.9% + 5.6% = 10.5% without flotation costs and 10.8% with flotation costs. The need for a flotation cost allowance is discussed at length later in my testimony. I reiterate that to the extent that MECO is riskier than average, the risk premium applicable to MECO is correspondingly higher.

Q. Dr. Morin, are risk premium studies widely used?

A. Yes, they are. Risk Premium analyses are widely used by analysts, investors, and expert witnesses. Most college-level corporate finance and/or investment management texts including Investments by Bodie, Kane, and Marcus, McGraw-Hill Irwin, 2002, which is a recommended textbook for CFA (Chartered Financial Analyst) certification and examination, contain detailed conceptual and empirical discussion of the risk premium approach. The latter is typically recommended as one of the three leading methods of estimating the cost of capital. Professor Brigham's best-selling corporate finance textbook (Financial Management: Theory and Practice, 11th ed., South-Western, 2005), recommends the use of risk premium studies, among others. Techniques of risk premium analysis are widespread in investment community reports. Professional certified financial analysts are certainly well versed in the use of this method.

Q. Are you concerned about the realism of the assumptions that underlie the historical risk premium method?

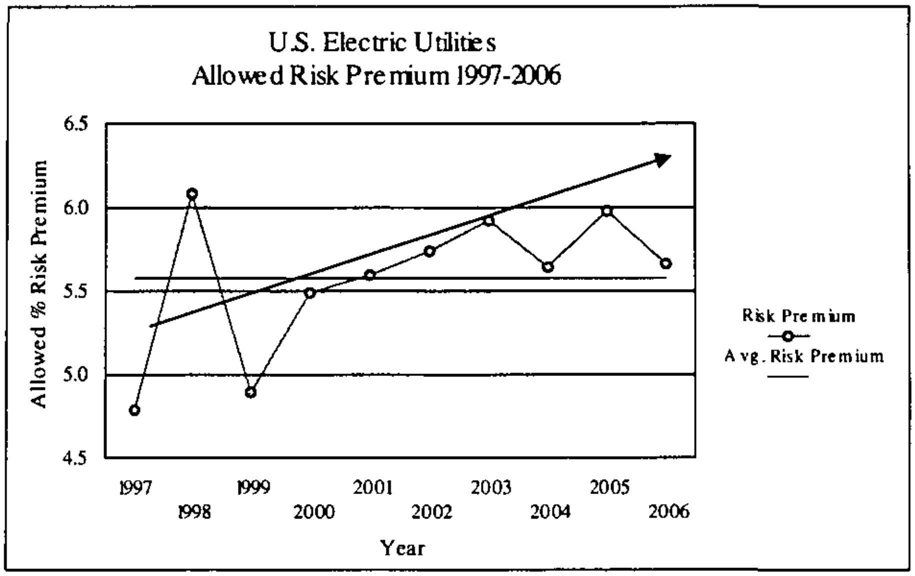
A. No, I am not, for they are no more restrictive than the assumptions that underlie the DCF model or the CAPM. While it is true that the method looks backward in time and assumes that the risk premium is constant over time, these assumptions are not necessarily restrictive. By employing returns realized over long time periods rather than returns realized over more recent time periods, investor return expectations and realizations converge. Realized returns can be substantially different from prospective returns anticipated by investors, especially when measured over short time periods. By ensuring that the risk premium study encompasses the longest possible period for which data are available, short-run periods during which investors earned a lower risk premium than they expected are offset by short-run periods during which investors earned a higher risk premium than they expected. Only over long time periods will investor return expectations and realizations converge, or else, investors would never commit any funds.

C. Allowed Risk Premiums

Q. Please describe your analysis of allowed risk premiums in the electric utility industry.

A. To estimate the Company's cost of common equity, I also examined the historical risk premiums implied in the ROEs allowed by regulatory commissions for electric utilities over the last decade relative to the contemporaneous level of the long-term Treasury bond yield. This variation of the risk premium approach is reasonable because allowed risk premiums are presumably based on the results of market-based methodologies (DCF, Risk Premium, CAPM, etc.) presented to regulators in rate hearings and on the actions of objective unbiased investors in a competitive marketplace. Historical allowed ROE data are readily available over long periods on a quarterly basis from Regulatory Research Associates (RRA) and easily verifiable from RRA publications and past commission decision archives.

The average ROE spread over long-term Treasury yields was 5.6% for the 1997-2006 time period, as shown by the horizontal line in the graph below. I note that this estimate is identical to that obtained from the historical risk premium study of the electric utility industry. The graph also shows the year-by-year allowed risk premium. The steady escalating trend of the risk premium in response to lower interest rates and rising competition is noteworthy.

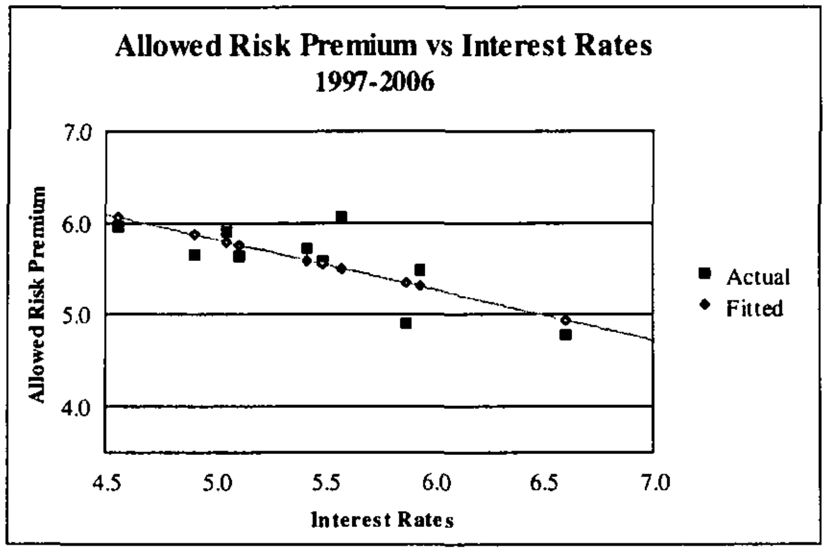


A careful review of these ROE decisions relative to interest rate trends reveals a narrowing of the risk premium in times of rising interest rates, and a widening of the premium as interest rates fall. The following statistical relationship between the risk premium (RP) and interest rates (YIELD) emerges over the last decade:

$$RP = 8.6029 - \underset{(t = 3.3)}{0.5543}\ YIELD \qquad R^2 = 0.58$$

The relationship is highly statistically significant[11] as indicated by the high R^2 and statistically significant t-value of the slope coefficient. The graph below shows a clear inverse relationship between the allowed risk premium and interest rates as revealed in past ROE decisions.

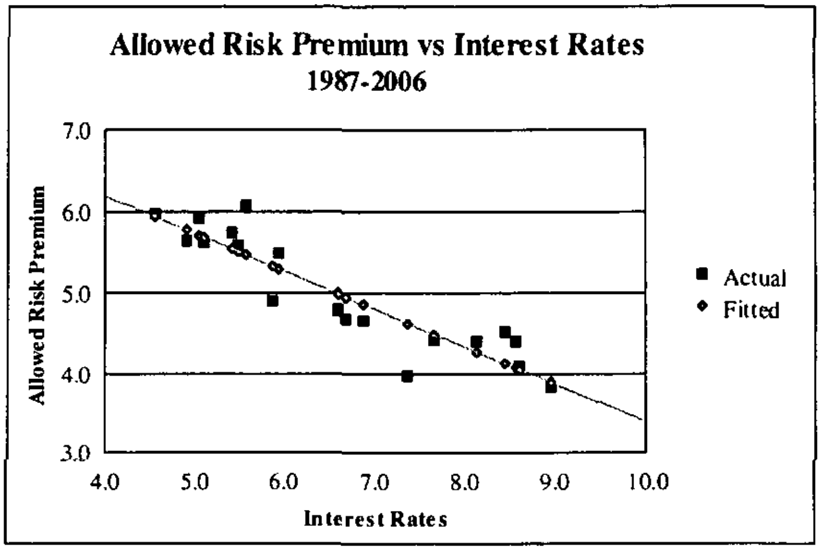
[11] The coefficient of determination R^2, sometimes called the "goodness of fit measure" is a measure of the degree of explanatory power of a statistical relationship. It is simply the ratio of the explained portion to the total sum of squares. The higher R^2 the higher is the degree of the overall fit of the estimated regression equation to the sample data. The t-statistic is a standard measure of the statistical significance of an independent variable in a regression relationship. A t-value above 2.0 is considered highly significant.



Inserting the current long-term Treasury bond yield of 4.9% in the above equation suggests that a risk premium estimate of 5.9% should be allowed for the average risk electric utility, implying a cost of equity of 10.8% for the average risk utility. No flotation cost adjustment is required here since the return figures are allowed book returns on common equity capital.

Q. Dr. Morin, does the observed relationship between allowed utility returns and interest rates hold over longer periods as well?

A. Yes, it does indeed. The relationship is even more significant over longer periods with a R^2 of 0.83 and a t-value of 9.5. The graph below illustrates the inverse relationship between the allowed risk premium and interest rates as revealed in some 550 past ROE decisions over the longest period over which such data are available from RRA, namely 1987-2006.



Q. Why did you rely on the last decade to conduct your allowed risk premium analysis?

A. Because allowed returns already reflect investor expectations, that is, are forward-looking in nature, the need for relying on long historical periods is minimized. The last decade is a reasonable period of analysis in the case of allowed returns in view of the stability of the inflation rate experienced over the last decade.

Q. Do investors take into account allowed returns in formulating their expectations?

A. Yes, they do. Investors do take into account returns granted by various regulators in formulating their risk and return expectations, as evidenced by the availability of commercial publications disseminating such data, including Value Line and RRA. Allowed returns, while certainly not a precise indication of a particular company's cost of equity capital, are nevertheless an important determinant of investor growth perceptions and investor expected returns.

Q. Do allowed returns reflect investor expectations?

A. As far as allowed risk premiums are concerned, regulators presumably base their allowed ROE decisions relative to the level of interest rates on a wide variety of evidence concerning investor expected returns submitted by various parties. Because allowed returns already reflect investor expectations, that is, are forward-looking in nature, the need for relying on long historical periods is minimized. The last decade is a reasonable period of analysis in the case of allowed returns in view of the stability of the inflation rate experienced over the last decade.

Q. Dr. Morin, how do you explain this inverse relationship between allowed returns and interest rates?

A. It is transparent from the above graph that allowed risk premiums vary inversely with the levels of interest rates. Regulators have systematically increased the authorized risk premium when interest rates declined, and decreased the authorized risk premium when interest rates increased. In other words, commission-authorized returns tend to moderate the impact of interest rate movements on allowed returns.

This phenomenon has been well documented for a long time. Published studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992), Maddox, Pippert and Sullivan (1995), and others demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates, rising when rates fell and declining when interest rates rose.[12] [13]

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[12] Brigham, E.F., Shome, D.K., and Vinson, S. R. "The Risk Premium Approach to Measuring a Utility's Cost of Equity." *Financial Management,* Spring 1985, 33-45. ("BSV") Harris, R.S. "Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return." *Financial Management,* Spring 1986, 58-67. Harris, R.S. and Marston, F.C. "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts." *Financial Management,* Summer 1992, 63-70. ("HM") Maddox, F.M., Pippert, D. T., and Sullivan, R.N. "An Empirical Study of Ex Ante Risk Premiums for the Electric Utility Industry" *Financial Management.* Autumn 1995, 89-95. ("MPS")

[13] It is important not to confuse the risk premium on the overall equity market and the risk premium specific to the utility industry.

The reason for this inverse relationship is that when interest rates rise, bondholders, whose interest rates are fixed, often suffer a decrease in the market value of their bonds, experiencing a capital loss. This item is referred to as interest rate risk. Stockholders, on the other hand, are more concerned with the firm's earning power. In order to avoid interest rate risk in an environment of rising interest rates, investors tend to become more willing to undertake equity investments which, although subject to some fear of loss of earning power, are less sensitive to the fear of interest rate risk. The resulting increase in the supply of funds available for such equity investments causes a downward pressure on the market price for equity. So, generally it is observed that if bondholders' fear of interest rate risk exceeds shareholders' fear of loss of earning power, the risk differential will narrow and hence the risk premium will shrink. This item is particularly true in high inflation environments. Interest rates rise as a result of accelerating inflation, and the interest rate risk of bonds intensifies more than the earnings risk of common stocks, which are partially hedged from the ravages of inflation. This phenomenon has been termed as a "lock-in" premium. Conversely in low interest rate environments when bondholders' interest rate fears subside and shareholders' loss of earning power dominate, the risk differential will widen and hence the risk premium will increase. This event has in fact occurred since 1998.

In short, the empirical evidence from the published academic literature demonstrates that the risk premium varies inversely with the level of interest rates.

Q. Please summarize your risk premium estimates.

A. The table below summarizes the ROE estimates obtained from the two risk premium studies. The average risk premium result is clearly 10.8%, as both estimates are identical.

Risk Premium Method	ROE
Historical	10.8%
Allowed Risk Premium	10.8%

D. DCF Estimates

Q. Please describe the DCF approach to estimating the cost of equity capital.

A. According to DCF theory, the value of any security to an investor is the expected discounted value of the future stream of dividends or other benefits. One widely used method to measure these anticipated benefits in the case of a non-static company is to examine the current dividend plus the increases in future dividend payments expected by investors. This valuation process can be represented by the following formula, which is the traditional DCF model:

$$K_e = D_1/P_o + g$$

where: K_e = investors' expected return on equity

D_1 = expected dividend at the end of the coming year

P_o = current stock price

g = expected growth rate of dividends, earnings, stock price, book value

The standard traditional DCF formula states that under certain assumptions, which are described in the next paragraph, the equity investor's expected return, K_e, can be viewed as the sum of an expected dividend yield, D_1/P_o, plus the expected growth rate of future dividends and stock price, g. The returns anticipated at a given market price are not directly observable and must be estimated from statistical market information. The idea of the market value approach is to infer 'K_e' from the observed share price, the observed dividend, and an estimate of investors' expected future growth.

The assumptions underlying this valuation formulation are well known, and are discussed in detail in Chapter 4 of my reference book, *Regulatory Finance*, and Chapter 8 of my new text, *The New Regulatory Finance*. The standard DCF model requires the following main assumptions: a constant average growth trend for both dividends and earnings, a stable dividend payout policy, a discount rate in excess of the expected growth rate, and a constant price-earnings multiple, which implies that growth in price is synonymous with growth in earnings and dividends. The standard DCF model also assumes that dividends are paid at the end of each year when in fact dividend payments are normally made on a quarterly basis.

Q. Is the constant growth DCF model applicable under all circumstances?

A. No, it is not, as I discussed earlier in my testimony. For companies in a mature industry, such as the electric utility industry had been until recent years, a constant growth rate is a reasonable assumption. For companies in a more dynamic evolving industry, such as the electric utility business, this assumption may not be reasonable; the dividend growth rate may be expected to converge only over time toward a steady-state long-run level.

Q. How did you estimate MECO's cost of equity with the DCF model?

A. I applied the DCF model to two proxies for the electric utility industry: a group of investment-grade dividend-paying integrated electric utilities and a group consisting of the companies that make up Moody's Electric Utility Index.

In order to apply the DCF model, two components are required: the expected dividend yield (D_1/P_0) and the expected long-term growth (g). The expected dividend D_1 in the annual DCF model can be obtained by multiplying the current indicated annual dividend rate by the growth factor (1 + g).

From a conceptual viewpoint, the stock price to employ in calculating the dividend yield is the current price of the security at the time of estimating the cost of equity. The reason is that current stock price provides a better indication of expected future prices than any other price in an efficient market. An efficient market implies that prices adjust rapidly to the arrival of new information. Therefore, the current price reflects the fundamental economic value of a security. A considerable body of empirical evidence indicates that capital markets are efficient with respect to a broad set of information. This implies that observed current prices represent the fundamental value of a security, and that a cost of capital estimate should be based on current prices.

In implementing the DCF model, I have used the current dividend yields reported in the latest edition of Value Line's VLIA software. Basing dividend yields on average results from a large group of companies reduces the concern that idiosyncrasies of individual company stock prices will result in an unrepresentative dividend yield.

Q. How did you estimate the growth component of the DCF model?

A. The principal difficulty in calculating the required return by the DCF approach is in ascertaining the growth rate that investors currently expect. Since no explicit estimate of expected growth is observable, proxies must be employed.

As proxies for expected growth, I examined growth estimates developed by professional analysts employed by large investment brokerage institutions. Projected long-term growth rates actually used by institutional investors to determine the desirability of investing in different securities influence investors' growth anticipations. These forecasts are made by large reputable organizations, and the data are readily available to investors and are representative of the consensus view of investors. Because of the dominance of institutional investors in investment management and security selection, and their influence on individual investment decisions, analysts' growth forecasts influence investor growth expectations and provide a sound basis for estimating the cost of equity with the DCF model. Growth rate forecasts of several analysts are available from published investment newsletters and from systematic compilations of analysts' forecasts, such as those tabulated by Zacks Investment Research Inc. ("Zacks"). I used analysts' long-term growth forecasts contained in Zacks as proxies for investors' growth expectations in applying the DCF model. I also used Value Line's growth forecast as an additional proxy.

Q. Why did you reject the use of historical growth rates in applying the DCF model to electric utilities?

A. I have rejected historical growth rates as proxies for expected growth in the DCF calculation for two reasons. First, historical growth patterns are already incorporated in analysts' growth forecasts that should be used in the DCF model, and are therefore somewhat redundant.

Second, historical growth rates have little relevance as proxies for future long-term growth at this time. They are downward-biased by the sluggish earnings performance in the last five years, due to the structural transformation of the electric utility industry from a regulated monopoly to a more competitive environment. Several electric utility companies have experienced a negative earnings growth rate. The industry as a whole has experienced very little dividend growth over the past five years.

Columns 3, 4, and 5 of Exhibit MECO-1603 display the historical growth in earnings, dividends, and book value per share over the last five years for the electric utility companies that make up Value Line's Electric Utility composite group. The average historical growth rates in earnings, dividends, and book value for the group are 0.0%, -0.3%, and 2.1% over the past 5 years, respectively. Several companies have experienced a negative earnings growth rate, as evidenced by the numerous historical growth rates reported on the table that are negative.

These anemic historical growth rates are certainly not representative of these companies' long-term earning power, and produce unreasonably low DCF estimates, well outside reasonable limits of probability and common sense. To illustrate, adding the historical growth rates of 0.0%, -0.3%, and 2.1% to the average dividend yield of approximately 4.0% prevailing currently for those same companies, produces preposterous cost of equity estimates of 4.0%, 3.7%, and 6.1%, using earnings, dividends, and book value growth rates, respectively. Of course, these estimates of equity costs are outlandish as they are less than the cost of long-term debt for these companies.

Q. Did you consider any other method of estimating expected growth in the DCF model?

A. Yes, I did. I considered using the so-called "sustainable growth" method, also referred to as the "retention growth" method. According to this method, future growth is estimated by multiplying the fraction of earnings expected to be retained by the company, 'b', by the expected return on book equity, 'ROE'. That is,

$$g = b \times ROE$$

where: g = expected growth rate in earnings/dividends

b = expected retention ratio

ROE = expected return on book equity

However, I do not generally subscribe to the growth results produced by this particular method for several reasons. First, the sustainable method of predicting growth is only accurate under the assumptions that the return on book equity (ROE) is constant over time and that no new common stock is issued by the company, or if so, it is sold at book value. Second, and more importantly, the sustainable growth method contains a logic trap: the method requires an estimate of ROE to be implemented. But if the ROE input required by the model differs from the recommended return on equity, a fundamental contradiction in logic follows. Third, the empirical finance literature demonstrates that the sustainable growth method of determining growth is not as significantly correlated to measures of value, such as stock prices and price/earnings ratios, as analysts' growth forecasts. I therefore placed no reliance on this method.

Q. Did you consider projected dividend growth in applying the DCF model?

A. No, not at this time. The reason is that it is widely expected that utilities will continue to lower their dividend payout ratio over the next several years. In other words, earnings and dividends are not expected to grow at the same rate in the future.

Whenever the dividend payout ratio is expected to change, the intermediate growth rate in dividends cannot equal the long-term growth rate, because dividend/earnings growth must adjust to the changing payout ratio. The assumptions of constant perpetual growth and constant payout ratio are clearly not met. Thus, the implementation of the standard DCF model is of questionable relevance in this circumstance.

Dividend growth rates are unlikely to provide a meaningful guide to investors' growth expectations for utilities in general. This result is because utilities' dividend policies have become increasing conservative as business risks in the industry have intensified steadily. Dividend growth has remained largely stagnant in past years as utilities are increasingly conserving financial resources in order to hedge against rising business risks. As a result, investors' attention has shifted from dividends to earnings. Therefore, earnings growth provides a more meaningful guide to investors' long-term growth expectations. Indeed, it is growth in earnings that will support future dividends and share prices.

As a practical matter, there are very few dividend growth forecasts available in sharp contrast to the wide availability of earnings growth forecasts.

Q. Is there any empirical evidence documenting the importance of earnings in evaluating investors' expectations in the investment community?

A. Yes, there is an abundance of evidence attesting to the importance of earnings in assessing investors' expectations. First, the sheer volume of earnings forecasts available from the investment community relative to the scarcity of dividend forecasts attests to their importance. To illustrate, Value Line, Zacks Investment, First Call Thompson, MSN Investor, Yahoo Finance, and Multex provide comprehensive compilations of investors' earnings forecasts, to name some. The fact that these investment information providers focus on growth in earnings rather than growth in dividends indicates that the investment community regards earnings growth as a superior indicator of future long-term growth. Second, Value Line's principal investment rating assigned to individual stocks, Timeliness Rank, is based primarily on earnings, which accounts for 65% of the ranking.

Q. Dr. Morin, how did you approach the composition of comparable groups in order to estimate MECO's cost of equity with the DCF method?

A. Because MECO is not publicly traded, the DCF model cannot be applied to

MECO and proxies must be used. There are two possible approaches in forming proxy groups of companies.

The first approach is to apply cost of capital estimation techniques to a select group of companies directly comparable in risk to MECO. These companies are chosen by the application of stringent screening criteria to a universe of electric utility stocks in an attempt to identify companies with the same investment risk as MECO. Examples of screening criteria include bond rating, beta risk, size, percentage of revenues from electric utility operations, and common equity ratio. The end result is a small sample of companies with a risk profile similar to that of MECO, provided the screening criteria are defined and applied correctly.

The second approach is to apply cost of capital estimation techniques to a large group of electric utilities representative of the electric utility industry average and then make adjustments to account for any difference in investment risk between the company and the industry average. As explained below, in view of substantial changes in circumstances in the electric utility industry, I have chosen the latter approach.

In the current unstable industry environment, it is important to select relatively large sample sizes representative of the electric utility industry as a whole, as opposed to small sample sizes consisting of a handful of companies. This is because the electric utility industry capital market data is highly unstable at this time. As a result of this instability, the composition of small groups of companies is very fluid, with companies exiting the sample due to dividend suspensions or reductions, insufficient or unrepresentative historical data due to recent mergers, impending merger or acquisition, and changing corporate identities due to restructuring activities.

From a statistical standpoint, confidence in the reliability of the DCF model result is considerably enhanced when applying the DCF model to a large group of companies. Any distortions introduced by measurement errors in the two DCF components of equity return for individual companies, namely dividend yield and growth are mitigated. Utilizing a large portfolio of companies reduces the chance of either overestimating or underestimating the cost of equity for an individual company. For example, in a large group of companies, positive and negative deviations from the expected growth will tend to cancel out owing to the law of large numbers, provided that the errors are independent[14]. The average growth rate of several companies is less likely to diverge from expected growth than is the estimate of growth for a single firm. More generally, the assumptions of the DCF model are more likely to be fulfilled for a large group of companies than for any single firm or for a small group of companies.

Moreover, small samples are subject to measurement error, and in violation

[14] If σ_i^2 represents the average variance of the errors in a group of N companies, and σ_{ij} the average covariance between the errors, then the variance of the error for the group of N companies, σ_N^2 is:

$$\sigma_N^2 = \frac{1}{N}\bar{\sigma}_i^2 + \frac{N-1}{N}\bar{\sigma}_{ij}$$

If the errors are independent, the covariance between them (σ_{ij}) is zero, and the variance of the error for the group is reduced to:

$$\sigma_N^2 = \frac{1}{N}\sigma_i^2$$ As N gets progressively larger, the variance gets smaller and smaller.

of the Central Limit Theorem of statistics[15]. From a statistical standpoint, reliance on robust sample sizes mitigates the impact of possible measurement errors and vagaries in individual companies' market data. Examples of such vagaries include dividend suspension, insufficient or unrepresentative historical data due to a recent merger, impending merger or acquisition, and a new corporate identity due to restructuring.

The point of all this is that the use of a handful of companies in a highly fluid and unstable industry produces fragile and statistically unreliable results. A far safer procedure is to employ large sample sizes representative of the industry as a whole and apply subsequent risk adjustments to the extent that the company's risk profile differs from that of the industry average.

Q. Please describe your first proxy group for the electric utility business?

A. As a first proxy for the electric utility business, I examined a group of investment-grade utilities designated as combination gas and electric utilities by AUS Utility Reports and whose utility revenues constitute at least 50% of their total revenues. Companies below investment-grade, that is, companies with a bond rating below Baa3, were eliminated as well as those companies without Value Line coverage. Most of these companies are labeled "vertically integrated" electric utilities by S&P in its analysis of utility business risks, the same as HEI, MECO's parent company. The final sample is shown on Page 1 of Exhibit MECO-1604 and

[15] The Central Limit Theorem describes the characteristics of the distribution of values we would obtain if we were able to draw an infinite number of random samples of a given size from a given population and we calculated the mean of each sample. The Central Limit Theorem asserts: [1] The mean of the sampling distribution of means is equal to the mean of the population from which the samples were drawn. [2] The variance of the sampling distribution of means is equal to the variance of the population from which the samples were drawn divided by the size of the samples. [3] If the original population is distributed normally, the sampling distribution of means will also be normal. If the original population is not normally distributed, the sampling distribution of means will increasingly approximate a normal distribution as sample size increases.

includes electric utility companies engaged in predominantly integrated electric utility activities. These companies on average derive 70% of their revenues from electric utility operations. The same group was discussed earlier in connection with beta estimates and is retained for the DCF analysis.

Q. What DCF results did you obtain for your first group of electric utilities using the Value Line growth projections?

A. For purposes of conducting the DCF analysis, as shown on Page 1 of Exhibit MECO-1604, one company (Public Service Enterprise) was eliminated on account of recent merger negotiations. Value Line's growth projection of 18.5% for Teco Energy was deemed unsustainable and replaced with the analyst growth forecast.

As shown on Column 2 of page 2 of Exhibit MECO-1604, the average long-term growth forecast obtained from Value Line is 5.5% for this group. Adding this growth rate to the average expected dividend yield of 4.0% shown in Column 3 produces an estimate of equity costs of 9.5% for the group. Recognition of flotation costs brings the cost of equity estimate to 9.7%, shown in Column 5.

Q. What DCF results did you obtain using the analysts' consensus growth forecast?

A. From the original sample of 21 companies shown on page 1 of Exhibit MECO-1605, CH Energy, MGE Energy, and UniSource were eliminated as no analysts' growth forecasts were available from Zacks. Public Service Enterprise was eliminated on account of recent merger negotiations. For the remaining 17 companies, using the consensus analysts' earnings growth forecast published by Zacks of 6.4% instead of the Value Line forecast, the cost of equity for the group is 10.5%. Recognition of flotation costs brings the cost of equity estimate to 10.7%, shown in Column 5. This analysis is shown on page 2 of Exhibit MECO-1605.

Q. What DCF results did you obtain for Moody's electric utilities group?

A. Page 1 of Exhibit MECO-1606 displays the electric utilities that make up Moody's Electric Utility Index. No growth forecast was available for Progress Energy from Value Line. Public Service Enterprise was discarded on account of ongoing merger activity. As shown on Column 2 of page 2 of Exhibit MECO-1606, the average long-term growth forecast obtained from Value Line is 6.0% for this group. Coupling this growth rate with the average expected dividend yield of 4.5% shown in Column 3 produces an estimate of equity costs of 10.5% for the group unadjusted for flotation costs. Adding an allowance for flotation costs to the results of Column 4 brings the cost of equity estimate to 10.8%, shown in Column 5.

Using the consensus analysts' earnings growth forecast of 5.7% from Zacks instead of the Value Line growth forecast, the cost of equity for the Moody's group is 10.1% for the group unadjusted for flotation costs. Adding an allowance for flotation costs to the results brings the cost of equity estimate to 10.4%. This analysis is displayed on Pages 1 and 2 of Exhibit MECO-1607. No growth projections were available for CH Energy and Duquesne Light, and those companies were therefore eliminated from the group. Public Service Enterprise was discarded on account of ongoing merger activity.

Q. Please summarize your DCF estimates.

A. The table below summarizes the DCF estimates. The average of the DCF results is 10.4%.

DCF STUDY	ROE
DCF Integrated Electric Utilities Value Line Growth	9.7%
DCF Integrated Electric Utilities Zacks Growth	10.7%
DCF Moody's Elec Utilities Value Line Growth	10.8%
DCF Moody's Elec Utilities Zacks Growth	10.4%

Q. Do these DCF results understate the cost of equity for MECO?

A. Yes, they do. As discussed at length earlier, application of the standard DCF model to utility stocks understates the investor's expected return when the M/B ratio of a given stock exceeds 1.0, as is the case presently.

E. **Need for Flotation Cost Adjustment**

Q. Please describe the need for a flotation cost allowance.

A. All the market-based estimates reported above include an adjustment for flotation costs. The simple fact of the matter is that common equity capital is not free. Flotation costs associated with stock issues are exactly like the flotation costs associated with bonds and preferred stocks. Flotation costs are not expensed at the time of issue, and therefore must be recovered via a rate of return adjustment. This is done routinely for bond and preferred stock issues by most regulatory commissions, including FERC. Clearly, the common equity capital accumulated by the Company is not cost-free. The flotation cost allowance to the cost of common equity capital is discussed and applied in most corporate finance textbooks; it is unreasonable to ignore the need for such an adjustment.

Flotation costs are very similar to the closing costs on a home mortgage. In the case of issues of new equity, flotation costs represent the discounts that must be provided to place the new securities. Flotation costs have a direct and an indirect component. The direct component is the compensation to the security underwriter for his marketing/consulting services, for the risks involved in distributing the issue, and for any operating expenses associated with the issue (printing, legal, prospectus, etc.). The indirect component represents the downward pressure on the stock price as a result of the increased supply of stock from the new issue. The latter component is frequently referred to as "market pressure."

Investors must be compensated for flotation costs on an ongoing basis to the extent that such costs have not been expensed in the past, and therefore the adjustment must continue for the entire time that these initial funds are retained in the firm. MECO-1609 to my testimony discusses flotation costs in detail, and shows: (1) why it is necessary to apply an allowance of 5% to the dividend yield component of equity cost by dividing that yield by 0.95 (100% - 5%) to obtain the fair return on equity capital; (2) why the flotation adjustment is permanently required to avoid confiscation even if no further stock issues are contemplated; and (3) that flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years.

By analogy, in the case of a bond issue, flotation costs are not expensed but are amortized over the life of the bond, and the annual amortization charge is embedded in the cost of service. The flotation adjustment is also analogous to the process of depreciation, which allows the recovery of funds invested in utility plant. The recovery of bond flotation expense continues year after year, irrespective of whether the Company issues new debt capital in the future, until recovery is complete, in the same way that the recovery of past investments in plant and equipment through depreciation allowances continues in the future even if no new construction is contemplated. In the case of common stock that has no finite life, flotation costs are not amortized. Thus, the recovery of flotation cost requires an upward adjustment to the allowed return on equity.

A simple example will illustrate the concept. A stock is sold for $100, and investors require a 10% return, that is, $10 of earnings. But if flotation costs are 5%, the Company nets $95 from the issue, and its common equity account is credited by $95. In order to generate the same $10 of earnings to the shareholders, from a reduced equity base, it is clear that a return in excess of 10% must be allowed on this reduced equity base, here 10.52%.

According to the empirical finance literature discussed in MECO-1609, total flotation costs amount to 4% for the direct component and 1% for the market pressure component, for a total of 5% of gross proceeds. This in turn amounts to approximately 30 basis points, depending on the magnitude of the dividend yield component. To illustrate, dividing the average expected dividend yield of around 5.0% for utility stocks by 0.95 yields 5.3%, which is 30 basis points higher.

Sometimes, the argument is made that flotation costs are real and should be recognized in calculating the fair return on equity, but only at the time when the expenses are incurred. In other words, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument is valid only if the Company has already been compensated for these costs. If not, the argument is without merit. My own recommendation is that investors be compensated for flotation costs on an on-going basis rather than through expensing, and that the flotation cost adjustment continue for the entire time that these initial funds are retained in the firm.

There are several sources of equity capital available to a firm including: common equity issues, conversions of convertible preferred stock, dividend reinvestment plan, employees' savings plan, warrants, and stock dividend programs. Each carries its own set of administrative costs and flotation cost components, including discounts, commissions, corporate expenses, offering spread, and market pressure. The flotation cost allowance is a composite factor that reflects the historical mix of sources of equity. The allowance factor is a build-up of historical flotation cost adjustments associated and traceable to each component of equity at its source. It is impractical and prohibitively costly to start from the inception of a company and determine the source of all present equity. A practical solution is to identify general categories and assign one factor to each category. My recommended flotation cost allowance is a weighted average cost factor designed to capture the average cost of various equity vintages and types of equity capital raised by the Company.

Q. Is a flotation cost adjustment required for an operating subsidiary like MECO that does not trade publicly?

A. Yes, it is. It is sometimes alleged that a flotation cost allowance is inappropriate if the utility is a subsidiary whose equity capital is obtained from its ultimate parent, in this case, HEI. This objection is unfounded since the parent-subsidiary relationship does not eliminate the costs of a new issue, but merely transfers them to the parent. It would be unfair and discriminatory to subject parent shareholders to dilution while individual shareholders are absolved from such dilution. Fair treatment must consider that, if the utility-subsidiary had gone to the capital markets directly, flotation costs would have been incurred.

III. SUMMARY AND RECOMMENDATION ON COST OF EQUITY

Q. Please summarize your results and recommendation.

A. To arrive at my final recommendation, I performed four risk premium analyses. For the first two risk premium studies, I applied the CAPM and an empirical approximation of the CAPM using current market data. The other two risk premium analyses were performed on aggregate historical and allowed risk premium data from the electric utility industry. I also performed DCF analyses on two surrogates for the electric utility industry: a group of investment-grade integrated electric utilities and a group of electric utilities representative of the industry as proxied by Moody's Electric Utility Index. The results from all the various tests are summarized in the table below.

STUDY	ROE
CAPM	11.6%
Empirical CAPM	11.8%
Risk Premium Elec	10.8%
Allowed Risk Premium	10.8%
DCF Integrated Electric Utilities Value Line Growth	9.7%
DCF Integrated Electric Utilities Zacks Growth	10.7%
DCF Moody's Elec Utilities Value Line Growth	10.8%
DCF Moody's Elec Utilities Zacks Growth	10.4%

The average result from the three principal methodologies is as follows:

CAPM	11.7%
Risk Premium	10.8%
DCF	10.4%
AVERAGE	11.0%

The overall average result is 11.0% for the average risk electric utility.

Q. Should the cost of equity estimates be further adjusted to account for MECO being riskier than the average electric utility?

A. Yes. The cost of equity estimates derived from the various comparable groups reflect the risk of the average electric utility. To the extent that these estimates are drawn from a less risky group of companies, the expected equity return applicable to the riskier MECO is downward-biased.

MECO possesses small revenue and asset bases, both in absolute terms and relative to other utilities. Investment risk increases as company size diminishes, all else remaining constant. The size phenomenon is well documented in the finance literature. Small companies have very different returns than large ones and on average those returns have been higher. The greater risk of small stocks does not fully account for their higher returns over many historical periods. The average small stock premium is well in excess of that of the average stock, more than could be expected by risk differences alone, suggesting that the cost of equity for small stocks is considerably larger than for large capitalization stocks. In addition to earning the highest average rates of return, small stocks also have the highest volatility, as measured by the standard deviation of returns.

Q. Has the Commission recognized the effect of size on investment risk in the past?

A. Yes, it has. In Amended Decision and Order No. 16922 in Docket No. 97-0346, the Commission agreed that a size adjustment is appropriate for Maui Electric Company, Limited on account of its smaller size.

Q. What is your conclusion with respect to MECO's overall investment risk?

A. The net result of these distinctive risk factors is that MECO possesses slightly above average investment risk relative to U.S. electric utilities. Therefore, I have adjusted the initial cost of equity of 11.0% based on the industry average upward by a conservative 25 basis points, raising the cost of equity from 11.0% to 11.25%. This adjustment reflects the Company's much smaller size.

Q. Dr. Morin, what capital structure assumption underlies your recommended return on MECO's common equity capital?

A. My recommended return on common equity for MECO is predicated on the adoption of a test year capital structure consisting of approximately 55% common equity capital.

Q. Dr. Morin, can you please comment on the impact of the commission's energy cost adjustment clause on the company's business risk and on your recommended return?

A. Yes, certainly. Because of the Company's predominantly oil-based generating capacity, a dominant element of business risk peculiar to MECO is a significant reliance on fuel oil and the potential risks associated with variations in the price of oil. Mitigating this aspect of MECO's business risk is the Commission's continuation of a favorable energy cost adjustment clause, decreasing the Company's risk of not recovering its substantial fuel costs.

The Energy Cost Adjustment Clause ("ECAC") serves to reimburse MECO for prudently-incurred energy costs in a manner that minimizes the negative financial effects caused by regulatory lag. Consideration of energy costs in a manner that lowers uncertainty and risk represents the mainstream position on this issue across the United States. Accordingly, the financial community relies on the presence of energy cost recovery mechanisms to protect investors from the variability of fuel and purchased power costs that can have a substantial impact on the credit profile of a utility, even when prudently managed. To illustrate, it is my understanding that bond rating agencies would place considerably more weight on the Company's purchased power contracts as debt equivalents in the absence of ECAC, thus weakening the Company's financial integrity. The ECAC mitigates a portion of the risk and uncertainty related to the day-to-day management of a regulated utility's operations. Conversely, the absence of such protection is factored into the Company's credit profile as a negative element which in turn raises its cost of capital, as discussed above.

The approval of energy cost recovery mechanisms by regulatory commissions is widespread in the utility business. Approval of fuel adjustment clauses, purchased water adjustment clauses, and purchased gas adjustment clauses has become widespread. All else remaining constant, such clauses reduce investment risk on an absolute basis and constitute sound regulatory policy.

I believe that in the absence of the Commission renewal of the ECAC requested by MECO in this proceeding, MECO's financial condition would deteriorate, its customers would be at risk of having to pay higher rates due to access to capital becoming more expensive for MECO, and my recommended return would be significantly higher. This situation would have a substantial negative effect on MECO and its customers because of the magnitude of the energy cost component in its cost of service.

I believe that approval of MECO's request for continued approval of its ECAC is fair to MECO, its customers, and investors. I believe that the ECAC deals with the cost of fuel and purchased energy, as well as with the mix of resources, which can vary month-to-month and which can represent a considerable financial outlay, on a consistent basis, without need for recurring regulatory proceedings that are time-consuming, costly, and, significantly, create uncertainty within the financial community.

My recommendation is predicated on the continuation of the Company's current energy cost adjustment clause.

Q. Dr. Morin, what is your final conclusion regarding MECO's cost of common equity capital?

A. Based on the results of all my analyses, the application of my professional judgment, and the risk circumstances of MECO, it is my opinion that a just and reasonable return on the common equity capital of MECO's electric utility operations in the State of Hawaii at this time is 11.25%.

Q. How does the Commission's Recent Order No. 23223 in Docket No. 05-0310 influence your recommendation?

A. On January 26, 2007 in Decision and Order No. 23223 in Docket No. 05-0310, the PUC denied the electric utilities' request to record a regulatory asset the amount that would otherwise be charged against stockholders' equity as a result of recording a minimum pension liability as prescribed by SFAS No. 87. Since this order did not address the ratemaking treatment of pensions, I do not believe that this order, by itself, exerts any material impact on the Company's risk and my ROE recommendation at this time.

Total investment risk results from a multi-dimensional blend of several factors, including demand risks, regulatory risks, financial risks, and size. The demand risk component can in turn be disaggregated into sub-factors, including concentration of demand, customer mix, and service territory economics. It is difficult to quantify the exact impact of any given factor, such as business risk, on the company's total risk, let alone the impact of sub-factors. Investors examine a number of qualitative and quantitative factors before rendering a risk decision, that such factors are considered both individually and collectively.

Q. Is the return on investor-funded net pension assets (i.e. the inclusion of net pension asset in rate base) and return on investor-provided capital (i.e. restoring the equity balance in the cost of capital calculation for the non-cash charge for accumulated other comprehensive income) important to investors?

A. Yes, obviously it is important to investors to earn a return on all their invested capital.

Q. Would your recommended rate of return on equity change if the Company did not get the regulatory treatment for pension that it is seeking?

A. Yes, my current recommendation is based on the assumption that the Company gets the regulatory treatment of pension that it is seeking. If, for example, the Company's equity ratio were to decrease by 1%, the return expectation would increase approximately 10 basis points.

Q. Dr. Morin, do you have any general comment on recent regulatory policies enacted by the Commission?

A. Yes, I do. It is important that any reward/penalty regulatory mechanism, such as the standards for achieving minimum alternative energy targets that are currently under consideration by the Commission, be symmetrical in its apportionment of gains and losses between shareholders and ratepayers. While the preferred alternative is symmetry, if investors are to bear losses in failing to achieve alternative energy resources targets but not reap any gains for exceeding such targets, the effect on the policy's lack of symmetry on investor returns must be considered. Although I am not recommending such a premium at this time, a reasonable remedy is to add a risk premium that compensates investors for the limited upside returns/unlimited downside returns asymmetry versus comparable-risk companies, or at least err on the upper side of a ROE zone of reasonableness. Assuming some plausible probability distribution of investor equity returns both with and without the reward/penalty mechanism, the added premium is required to offset the plan's lack of upside potential and produce the same average return that would prevail under orthodox regulation. The "heads I win, tails you lose" effect on investor returns is discussed in Chapter 6 of my book The New Regulatory Finance.

Q. If capital market conditions change significantly between the date of filing your prepared testimony and the date oral testimony is presented, would this cause you to revise your estimated cost of equity?

A. Yes. Interest rates and security prices do change over time, and risk premiums change also, although much more sluggishly. If substantial changes were to occur between the filing date and the time my oral testimony is presented, I will update my testimony accordingly.

Q. Is there a relationship between financial risk and the authorized ROE?

A. There certainly is. The strength of that relationship is amplified for smaller utilities like MECO. A low authorized ROE increases the likelihood the utility will have to rely increasingly on debt financing for its capital needs. This creates the specter of a spiraling cycle that further increases risks to both equity and debt investors; the resulting increase in financing costs is ultimately borne by the utility's customers through higher capital costs and rates of returns.

Q. Is MECO's financial risk impacted by the authorized rate of return on equity?

A. Yes, it is. A low return on equity increases the likelihood that MECO will have to rely on debt financing for its capital needs. As the Company relies more on debt financing, its capital structure becomes more leveraged. Since debt payments are a fixed financial obligation to the utility, this decreases the operating income available for dividend growth. Consequently, equity investors face greater uncertainty about the future dividend potential of the firm. As a result, the company's equity becomes a riskier investment. The risk of default on the Company's bonds also increases, making the utility's debt a riskier investment. This increases the cost to the utility from both debt and equity financing and increases the possibility the Company will not have access to the capital markets for its outside financing needs, or if so, at prohibitive costs.

Q. Does this conclude your direct testimony?

A. Yes, it does.

RESUME OF ROGER A. MORIN

(November 2006)

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EDUCATIONAL HISTORY

- Bachelor of Electrical Engineering, McGill University, Montreal, Canada, 1967.
- Master of Business Administration, McGill University, Montreal, Canada, 1969.
- PhD in Finance & Econometrics, Wharton School of Finance, University of Pennsylvania, 1976.

EMPLOYMENT HISTORY

- Lecturer, Wharton School of Finance, Univ. of Pa., 1972-3.
- Assistant Professor, University of Montreal School of Business, 1973-1976.
- Associate Professor, University of Montreal School of Business, 1976-1979.
- Distinguished Professor of Finance, Georgia State University, 1979-2006.
- Professor of Finance for Regulated Industry and Director, Center for the Study of Regulated Industry, College of Business, Georgia State University, 1985-2006.
- Visiting Professor of Finance, Amos Tuck School of Business, Dartmouth College, Hanover, N.H., 1986.

OTHER BUSINESS ASSOCIATIONS

- Communications Engineer, Bell Canada, 1962-1967.
- Member of the Board of Directors, Financial Research Institute of Canada, 1974-1980.
- Co-founder and Director Canadian Finance Research Foundation, 1977.
- Vice-President of Research, Garmaise-Thomson & Associates, Investment Management Consultants, 1980-1981.
- Executive Visions Inc., Board of Directors, Member.
- Board of External Advisors, College of Business, Georgia State University, Member 1987-1991.

PROFESSIONAL CLIENTS

AGL Resources

AT & T Communications

Alagasco - Energen

Alaska Anchorage Municipal Light & Power

Alberta Power Ltd.

Ameren

American Water Works Company

Ameritech

Arkansas Western Gas

Baltimore Gas & Electric – Constellation Energy

Bangor Hydro-Electric

B.C. Telephone

B C GAS

Bell Canada

Bellcore

Bell South Corp.

Bruncor (New Brunswick Telephone)

Burlington-Northern

C & S Bank

Cajun Electric

Canadian Radio-Television & Telecomm. Commission

Canadian Utilities

Canadian Western Natural Gas

Cascade Natural Gas

Centel

PROFESSIONAL CLIENTS (CONT'D)

Centra Gas

Central Illinois Light & Power Co

Central Telephone

Central & South West Corp.

Chattanoogee Gas Company

Cincinnatti Gas & Electric

Cinergy Corp.

Citizens Utilities

City Gas of Florida

CN-CP Telecommunications

Commonwealth Telephone Co.

Columbia Gas System

Consolidated Natural Gas

Constellation Energy

Delmarva Power & Light Co

Deerpath Group

DTE Energy

Edison International

Edmonton Power Company

Elizabethtown Gas Co.

Emera

Energen

Engraph Corporation

Entergy Corp.

Entergy Arkansas Inc.

PROFESSIONAL CLIENTS (CONT'D)

Entergy Gulf States, Inc.

Entergy Louisiana, Inc.

Entergy Mississippi Power

Entergy New Orleans, Inc.

First Energy

Florida Water Association

Fortis

Garmaise-Thomson & Assoc., Investment Consultants

Gaz Metropolitain

General Public Utilities

Georgia Broadcasting Corp.

Georgia Power Company

GTE California - Verizon

GTE Northwest Inc. - Verizon

GTE Service Corp. - Verizon

GTE Southwest Incorporated - Verizon

Gulf Power Company

Havasu Water Inc.

Hawaii Electric Light Company, Inc.

Hawaiian Electric Company, Inc.

Heater Utilities – Aqua - America

Hope Gas Inc.

Hydro-Quebec

ICG Utilities

Illinois Commerce Commission

PROFESSIONAL CLIENTS (CONT'D)

Island Telephone

Jersey Central Power & Light

Kansas Power & Light

KeySpan Energy

Manitoba Hydro

Maritime Telephone

Metropolitan Edison Co.

Minister of Natural Resources Province of Quebec

Minnesota Power & Light

Mississippi Power Company

Missouri Gas Energy

Mountain Bell

Nevada Power Company

New Brunswick Power

Newfoundland Power Inc. - Fortis Inc.

New Tel Enterprises Ltd.

New York Telephone Co.

Norfolk-Southern

Northeast Utilities

Northern Telephone Ltd.

Northwestern Bell

Northwestern Utilities Ltd.

Nova Scotia Power – Emera Inc.

Nova Scotia Utility and Review Board

NUI Corp.

PROFESSIONAL CLIENTS (CONT'D)

NYNEX

Oklahoma G & E

Ontario Telephone Service Commission

Orange & Rockland

Pacific Northwest Bell

People's Gas System Inc.

People's Natural Gas

Pennsylvania Electric Co.

Pepco Holdings

Price Waterhouse

PSI Energy

Public Service Electric & Gas

Public Service of New Hampshire

Puget Sound Electric Co.

Quebec Telephone

Regie de l'Energie du Quebec

Rochester Telephone

San Diego Gas & Electric

SaskPower

Sierra Pacific Power Company

Southern Bell

Southern States Utilities

Southern Union Gas

South Central Bell

Sun City Water Company

PROFESSIONAL CLIENTS (CONT'D)

TECO Energy

The Southern Company

Touche Ross and Company

TransEnergie

Trans-Quebec & Maritimes Pipeline

TXU Corp

US WEST Communications

Union Heat Light & Power

Utah Power & Light

Vermont Gas Systems Inc.

MANAGEMENT DEVELOPMENT AND PROFESSIONAL EXECUTIVE EDUCATION

- Canadian Institute of Marketing, Corporate Finance, 1971-73
- Hydro-Quebec, "Capital Budgeting Under Uncertainty," 1974-75
- Institute of Certified Public Accountants, Mergers & Acquisitions, 1975-78
- Investment Dealers Association of Canada, 1977-78
- Financial Research Foundation, bi-annual seminar, 1975-79
- Advanced Management Research (AMR), faculty member, 1977-80
- Financial Analysts Federation, Educational chapter: "Financial Futures Contracts" seminar

MANAGEMENT DEVELOPMENT AND PROFESSIONAL EXECUTIVE EDUCATION (CONT'D)

- Exnet Inc. a.k.a. The Management Exchange Inc., faculty member 1981-2006
  National Seminars:

  Risk and Return on Capital Projects
  Cost of Capital for Regulated Utilities
  Capital Allocation for Utilities
  Alternative Regulatory Frameworks
  Utility Directors' Workshop
  Shareholder Value Creation for Utilities
  Real Options in Utility Capital Investments
  Fundamentals of Utility Finance in a Restructured Environment
  Contemporary Issues in Utility Finance

- Georgia State University College of Business, Management Development Program, faculty member, 1981-1994

EXPERT TESTIMONY & UTILITY CONSULTING AREAS OF EXPERTISE

Rate of Return

Capital Structure

Generic Cost of Capital

Costing Methodology

Depreciation

Flow-Through vs Normalization

Revenue Requirements Methodology

Utility Capital Expenditures Analysis

Risk Analysis

Capital Allocation

Divisional Cost of Capital, Unbundling

Incentive Regulation & Alternative Regulatory Plans

Shareholder Value Creation

Value-Based Management

REGULATORY BODIES

Federal Communications Commission

Federal Energy Regulatory Commission

Georgia Public Service Commission

South Carolina Public Service Commission

North Carolina Utilities Commission

Pennsylvania Public Service Commission

Ontario Telephone Service Commission

Quebec Telephone Service Commission

Newfoundland Board of Commissioners of Public Utilities

Georgia Senate Committee on Regulated Industries

Alberta Public Service Board

Tennessee Regulatory Authority

Oklahoma State Board of Equalization

Mississippi Public Service Commission

Minnesota Public Utilities Commission

Canadian Radio-Television & Telecommunications Comm.

New Brunswick Board of Public Commissioners

Alaska Public Utility Commission

National Energy Board of Canada

Florida Public Service Commission

Montana Public Service Commission

Arizona Corporation Commission

Quebec Natural Gas Board

Quebec Regie de l'Energie

New York Public Service Commission

<u>REGULATORY BODIES (CONT'D)</u>

Washington Utilities & Transportation Commission

Manitoba Board of Public Utilities

New Jersey Board of Public Utilities

Alabama Public Service Commission

Utah Public Service Commission

Nevada Public Service Commission

Louisiana Public Service Commission

Colorado Public Utilities Board

West Virginia Public Service Commission

Ohio Public Utilities Commission

California Public Service Commission

Hawaii Public Utilities Commission

Illinois Commerce Commission

British Columbia Board of Public Utilities

Indiana Utility Regulatory Commission

Minnesota Public Utilities Commission

Texas Public Utility Commission

Michigan Public Service Commission

Iowa Board of Public Utilities

Missouri Public Service Commission

Arkansas Public Service Commission

New Hampshire Public Utility Commission

Delaware Public Utility Commission

Washington Utilities & Transportation Commission

Virginia Public Service Commission

SERVICE AS EXPERT WITNESS

Southern Bell, So. Carolina PSC, Docket #81-201C

Southern Bell, So. Carolina PSC, Docket #82-294C

Southern Bell, North Carolina PSC, Docket #P-55-816

Metropolitan Edison, Pennsylvania PUC, Docket #R-822249

Pennsylvania Electric, Pennsylvania PUC,Docket#R-822250

Georgia Power, Georgia PSC, Docket # 3270-U, 1981

Georgia Power, Georgia PSC, Docket # 3397-U, 1983

Georgia Power, Georgia PSC, Docket # 3673-U, 1987

Georgia Power, F.E.R.C., Docket # ER 80-326, 80-327

Georgia Power, F.E.R.C., Docket # ER 81-730, 80-731

Georgia Power, F.E.R.C., Docket # ER 85-730, 85-731

Bell Canada, CRTC 1987

Northern Telephone, Ontario PSC

GTE-Quebec Telephone, Quebec PSC, Docket 84-052B

Newtel., Nfld. Brd of Public Commission PU 11-87

CN-CP Telecommunications, CRTC

Quebec Northern Telephone, Quebec PSC

Edmonton Power Company, Alberta Public Service Board

Kansas Power & Light, F.E.R.C., Docket # ER 83-418

NYNEX, FCC generic cost of capital Docket #84-800

Bell South, FCC generic cost of capital Docket #84-800

American Water Works - Tennessee, Docket #7226

Burlington-Northern - Oklahoma State Board of Taxes

Georgia Power, Georgia PSC, Docket # 3549-U

GTE Service Corp., FCC Docket #84-200

SERVICE AS EXPERT WITNESS (CONT'D)

Mississippi Power Co., Miss. PSC, Docket U-4761

Citizens Utilities, Ariz. Corp. Comm., D # U2334-86020

Quebec Telephone, Quebec PSC, 1986, 1987, 1992

Newfoundland L & P, Nfld. Brd. Publ Comm. 1987, 1991

Northwestern Bell, Minnesota PSC, #P-421/CI-86-354

GTE Service Corp., FCC Docket #87-463

Anchorage Municipal Power & Light, Alaska PUC, 1988

New Brunswick Telephone, N.B. PUC, 1988

Trans-Quebec Maritime, Nat'l Energy Brd. of Cda, '88-92

Gulf Power Co., Florida PSC, Docket #88-1167-EI

Mountain States Bell, Montana PSC, #88-1.2

Mountain States Bell, Arizona CC, #E-1051-88-146

Georgia Power, Georgia PSC, Docket # 3840-U, 1989

Rochester Telephone, New York PSC, Docket # 89-C-022

Noverco - Gaz Metro, Quebec Natural Gas PSC, #R-3164-89

GTE Northwest, Washington UTC, #U-89-3031

Orange & Rockland, New York PSC, Case 89-E-175

Central Illinois Light Company, ICC, Case 90-0127

Peoples Natural Gas, Pennsylvania PSC, Case

Gulf Power, Florida PSC, Case # 891345-EI

ICG Utilities, Manitoba BPU, Case 1989

New Tel Enterprises, CRTC, Docket #90-15

Peoples Gas Systems, Florida PSC

Jersey Central Pwr & Light, N.J. PUB, Case ER 89110912J

Alabama Gas Co., Alabama PSC, Case 890001

SERVICE AS EXPERT WITNESS (CONT'D)

Trans-Quebec Maritime Pipeline, Cdn. Nat'l Energy Board

Mountain Bell, Utah PSC,

Mountain Bell, Colorado PUB

South Central Bell, Louisiana PS

Hope Gas, West Virginia PSC

Vermont Gas Systems, Vermont PSC

Alberta Power Ltd., Alberta PUB

Ohio Utilities Company, Ohio PSC

Georgia Power Company, Georgia PSC

Sun City Water Company

Havasu Water Inc.

Centra Gas (Manitoba) Co.

Central Telephone Co. Nevada

AGT Ltd., CRTC 1992

BC GAS, BCPUB 1992

California Water Association, California PUC 1992

Maritime Telephone 1993

BCE Enterprises, Bell Canada, 1993

Citizens Utilities Arizona gas division 1993

PSI Resources 1993-5

CILCORP gas division 1994

GTE Northwest Oregon 1993

Stentor Group 1994-5

Bell Canada 1994-1995

PSI Energy 1993, 1994, 1995, 1999

SERVICE AS EXPERT WITNESS (CONT'D)

Cincinnati Gas & Electric 1994, 1996, 1999, 2004

Southern States Utilities, 1995

CILCO 1995, 1999, 2001

Commonwealth Telephone 1996

Edison International 1996, 1998

Citizens Utilities 1997

Stentor Companies 1997

Hydro-Quebec 1998

Entergy Gulf States Louisiana 1998, 1999, 2001, 2002, 2003

Detroit Edison, 1999, 2003

Entergy Gulf States, Texas, 2000, 2004

Hydro Quebec TransEnergie, 2001, 2004

Sierra Pacific Company, 2000, 2001, 2002

Nevada Power Company, 2001

Mid American Energy, 2001, 2002

Entergy Louisiana Inc. 2001, 2002, 2004

Mississippi Power Company, 2001, 2002

Oklahoma Gas & Electric Company, 2002 -2003

Public Service Electric & Gas, 2001, 2002

NUI Corp (Elizabethtown Gas Company), 2002

Jersey Central Power & Light, 2002

San Diego Gas & Electric, 2002

NB Power, 2002

Entergy New Orleans, 2002

Hydro-Quebec Distribution 2002

SERVICE AS EXPERT WITNESS (CONT'D)

PSI Energy 2003

Fortis – Newfoundland Power & Light 2002

Emera – Nova Scotia Power 2004

Hydro-Quebec TransEnergie 2004

Hawaiian Electric 2004

Missouri Gas Energy 2004

AGL Resources 2004

Arkansas Western Gas 2004

Public Service of New Hampshire 2005

Hawaiian Electric Company 2005

Delmarva Power & Light Company 2005

Union Heat Power & Light 2005

Puget Sound Electric Co 2006-01-16

Cascade Natural Gas 2006

PROFESSIONAL AND LEARNED SOCIETIES

- Engineering Institute of Canada, 1967-1972
- Canada Council Award, recipient 1971 and 1972
- Canadian Association Administrative Sciences, 1973-80
- American Association of Decision Sciences, 1974-1978
- American Finance Association, 1975-2002
- Financial Management Association, 1978-2002

ACTIVITIES IN PROFESSIONAL ASSOCIATIONS AND MEETINGS

- Chairman of meeting on "New Developments in Utility Cost of Capital", Southern Finance Association, Atlanta, Nov. 1982

- Chairman of meeting on "Public Utility Rate of Return", Southeastern Public Utility Conference, Atlanta, Oct. 1982

- Chairman of meeting on "Current Issues in Regulatory Finance", Financial Management Association, Atlanta, Oct. 1983

- Chairman of meeting on "Utility Cost of Capital", Financial Management Association, Toronto, Canada, Oct. 1984.

- Committee on New Product Development, FMA, 1985

- Discussant, "Tobin's Q Ratio", paper presented at Financial Management Association, New York, N.Y., Oct. 1986

- Guest speaker, "Utility Capital Structure: New Developments", National Society of Rate of Return Analysts 18th Financial Forum, Wash., D.C. Oct. 1986

- Opening address, "Capital Expenditures Analysis: Methodology vs Mythology," Bellcore Economic Analysis Conference, Naples Fla., 1988.

PAPERS PRESENTED

"An Empirical Study of Multi-Period Asset Pricing," annual meeting of Financial Management Assoc., Las Vegas Nevada, 1987.

"Utility Capital Expenditures Analysis: Net Present Value vs Revenue Requirements", annual meeting of Financial Management Assoc., Denver, Colorado, October 1985.

"Intervention Analysis and the Dynamics of Market Efficiency", annual meeting of Financial Management Assoc., San Francisco, Oct. 1982

"Intertemporal Market-Line Theory: An Empirical Study," annual meeting of Eastern Finance Assoc., Newport, R.I. 1981

"Option Writing for Financial Institutions: A Cost-Benefit Analysis", 1979 annual meeting Financial Research Foundation

PAPERS PRESENTED (CONT'D)

"Free-lunch on the Toronto Stock Exchange", annual meeting of Financial Research Foundation of Canada, 1978.

"Simulation System Computer Software SIMFIN", HP International Business Computer Users Group, London, 1975.

"Inflation Accounting: Implications for Financial Analysis." Institute of Certified Public Accountants Symposium, 1979.

OFFICES IN PROFESSIONAL ASSOCIATIONS

- President, International Hewlett-Packard Business Computers Users Group, 1977

- Chairman Program Committee, International HP Business Computers Users Group, London, England, 1975

- Program Coordinator, Canadian Assoc. of Administrative Sciences, 1976

- Member, New Product Development Committee, Financial Management Association, 1985-1986

- Reviewer: Journal of Financial Research

  Financial Management

  Financial Review

  Journal of Finance

PUBLICATIONS

"Risk Aversion Revisited", Journal of Finance, Sept. 1983

"Hedging Regulatory Lag with Financial Futures," Journal of Finance, May 1983. (with G. Gay, R. Kolb)

"The Effect of CWIP on Cost of Capital," Public Utilities Fortnightly, July 1986.

"The Effect of CWIP on Revenue Requirements" Public Utilities Fortnightly, August 1986.

"Intervention Analysis and the Dynamics of Market Efficiency," Time-Series Applications, New York: North Holland, 1983. (with K. El-Sheshai)

"Market-Line Theory and the Canadian Equity Market," Journal of Business Administration, Jan. 1982, M. Brennan, editor

"Efficiency of Canadian Equity Markets," International Management Review, Feb. 1978.

"Intertemporal Market-Line Theory: An Empirical Test," Financial Review, Proceedings of the Eastern Finance Association, 1981.

BOOKS

Utilities' Cost of Capital, Public Utilities Reports Inc., Arlington, Va., 1984.

Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 2004

Driving Shareholder Value, McGraw-Hill, January 2001.

The New Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 2006.

MONOGRAPHS

Determining Cost of Capital for Regulated Industries, Public Utilities Reports, Inc., and The Management Exchange Inc., 1982 - 1993. (with V.L. Andrews)

Alternative Regulatory Frameworks, Public Utilities Reports, Inc., and The Management Exchange Inc., 1993. (with V.L. Andrews)

Risk and Return in Capital Projects, The Management Exchange Inc., 1980. (with B. Deschamps)

Utility Capital Expenditure Analysis, The Management Exchange Inc., 1983.

Regulation of Cable Television: An Econometric Planning Model, Quebec Department of Communications, 1978.

"An Economic & Financial Profile of the Canadian Cablevision Industry," Canadian Radio-Television & Telecommunication Commission (CRTC), 1978.

Computer Users' Manual: Finance and Investment Programs, University of Montreal Press, 1974, revised 1978.

Fiber Optics Communications: Economic Characteristics, Quebec Department of Communications, 1978.

"Canadian Equity Market Inefficiencies", Capital Market Research Memorandum, Garmaise & Thomson Investment Consultants, 1979.

MISCELLANEOUS CONSULTING REPORTS

"Operational Risk Analysis: California Water Utilities," Calif. Water Association, 1993.

"Cost of Capital Methodologies for Independent Telephone Systems", Ontario Telephone Service Commission, March 1989.

"The Effect of CWIP on Cost of Capital and Revenue Requirements", Georgia Power Company, 1985.

MISCELLANEOUS CONSULTING REPORTS (CONT'D)

"Costing Methodology and the Effect of Alternate Depreciation and Costing Methods on Revenue Requirements and Utility Finances", Gaz Metropolitan Inc., 1985.

"Simulated Capital Structure of CN-CP Telecommunications: A Critique", CRTC, 1977.

"Telecommunications Cost Inquiry: Critique",CRTC,1977.

"Social Rate of Discount in the Public Sector", CRTC Policy Statement, 1974.

"Technical Problems in Capital Projects Analysis", CRTC Policy Statement, 1974.

RESEARCH GRANTS

"Econometric Planning Model of the Cablevision Industry", International Institute of Quantitative Economics, CRTC.

"Application of the Averch-Johnson Model to Telecommunications Utilities", Canadian Radio-Television Commission. (CRTC)

"Economics of the Fiber Optics Industry", Quebec Dept. of Communications.

"Intervention Analysis and the Dynamics of Market Efficiency", Georgia State Univ. College of Business, 1981.

"Firm Size and Beta Stability", Georgia State University College of Business, 1982.

"Risk Aversion and the Demand for Risky Assets", Georgia State University College of Business, 1981.

Chase Econometrics, Interactive Data Corp., Research Grant, $50,000 per annum, 1986-1989.

UNIVERSITY SERVICE

- University Senate, elected departmental senator 1987-1989, 1998-2002
- Faculty Affairs Committee, elected departmental representative
- Professional Continuing Education Committee member
- Director Master in Science (Finance) Program
- Course Coordinator, Corporate Finance, MBA program
- Chairman, Corporate Finance Curriculum Committee
- Executive Education: Departmental Coordinator 2000

INTEGRATED ELECTRIC UTILITIES
BETA ESTIMATES

	Company Name	Industry	Beta
1	Alliant Energy	UTILCENT	0.90
2	Ameren Corp.	UTILCENT	0.75
3	CH Energy Group	UTILEAST	0.85
4	Consol. Edison	UTILEAST	0.70
5	DTE Energy	UTILCENT	0.75
6	Energy East Corp.	UTILEAST	0.90
7	Entergy Corp.	UTILCENT	0.85
8	Exelon Corp.	UTILEAST	0.80
9	MGE Energy	UTILCENT	0.75
10	Northeast Utilities	UTILEAST	0.85
11	NSTAR	UTILEAST	0.80
12	Pepco Holdings	UTILEAST	0.85
13	PG&E Corp.	UTILWEST	1.15
14	PNM Resources	UTILWEST	1.00
15	PPL Corp.	UTILEAST	1.00
16	Public Serv. Enterprise	UTILEAST	0.95
17	Puget Energy Inc.	UTILWEST	0.80
18	TECO Energy	UTILEAST	1.05
19	UniSource Energy	UTILWEST	0.75
20	Wisconsin Energy	UTILCENT	0.80
21	Xcel Energy Inc.	UTILWEST	0.90
	AVERAGE		**0.86**

Source: VLIA 10/2006

MOODY'S ELECTRIC UTILITIES
BETA ESTIMATES

	Company Name	Industry	Beta
1	Amer. Elec. Power	UTILCENT	1.25
2	CH Energy Group	UTILEAST	0.85
3	Consol. Edison	UTILEAST	0.70
4	Constellation Energy	UTILEAST	1.00
5	Dominion Resources	UTILEAST	1.00
6	DPL Inc.	UTILCENT	0.95
7	Duquesne Light Hldgs	UTILEAST	0.95
8	Duke Energy	UTILEAST	1.20
9	Energy East Corp.	UTILEAST	0.90
10	Exelon Corp.	UTILEAST	0.80
11	FirstEnergy Corp.	UTILEAST	0.80
12	IDACORP Inc.	UTILWEST	1.00
13	NiSource Inc.	UTILCENT	0.90
14	OGE Energy	UTILCENT	0.75
15	PPL Corp.	UTILEAST	1.00
16	Progress Energy	UTILEAST	0.85
17	Public Serv. Enterprise	UTILEAST	0.95
18	Southern Co.	UTILEAST	0.65
19	TECO Energy	UTILEAST	1.05
20	Xcel Energy Inc.	UTILWEST	0.90
	AVERAGE		**0.92**

Source: VLIA 10/2006

MOODY'S ELECTRIC UTILITY COMMON STOCKS
OVER LONG-TERM TREASURY BONDS
ANNUAL LONG-TERM RISK PREMIUM ANALYSIS

Year	Long-Term Government Bond Yield (1)	20 year Maturity Bond Value (2)	Gain/Loss (3)	Interest (4)	Bond Total Return (5)	Moody's Electric Utility Stock Index (6)	Dividend (7)	Capital Gain/(Loss) % Growth (8)	Yield (9)	Stock Total Return (10)	Equity Risk Premium (11)	Equity Risk Premium over Yield (12)
1931	4.07%	1,000.00				43.23						
1932	3.15%	1,135.75	135.75	40.70	17.64%	39.42	2.22	-8.81%	5.14%	-3.68%	-21.32%	-6.83%
1933	3.36%	969.60	-30.40	31.50	0.11%	28.73	1.75	-27.12%	4.44%	-22.68%	-22.79%	-26.04%
1934	2.93%	1,064.73	64.73	33.60	9.83%	21.06	1.42	-26.70%	4.94%	-21.75%	-31.59%	-24.68%
1935	2.76%	1,025.99	25.99	29.30	5.53%	36.06	1.33	71.23%	6.32%	77.54%	72.01%	74.78%
1936	2.55%	1,032.74	32.74	27.60	6.03%	41.60	1.78	15.36%	4.94%	20.30%	14.27%	17.75%
1937	2.73%	972.40	-27.60	25.50	-0.21%	24.24	1.68	-41.73%	4.04%	-37.69%	-37.48%	-40.42%
1938	2.52%	1,032.83	32.83	27.30	6.01%	27.55	1.45	13.66%	5.98%	19.64%	13.62%	17.12%
1939	2.26%	1,041.65	41.65	25.20	6.68%	28.85	1.51	4.72%	5.48%	10.20%	3.51%	7.94%
1940	1.94%	1,052.84	52.84	22.60	7.54%	22.22	1.57	-22.98%	5.44%	-17.54%	-25.08%	-19.48%
1941	2.04%	983.64	-16.36	19.40	0.30%	13.45	1.27	-39.47%	5.72%	-33.75%	-34.06%	-35.79%
1942	2.46%	933.97	-66.03	20.40	-4.56%	14.29	1.28	6.25%	9.52%	15.76%	20.33%	13.30%
1943	2.48%	996.86	-3.14	24.60	2.15%	21.01	1.46	47.03%	10.22%	57.24%	55.10%	54.76%
1944	2.46%	1,003.14	3.14	24.80	2.79%	21.09	1.35	0.38%	6.43%	6.81%	4.01%	4.35%
1945	1.99%	1,077.23	77.23	24.60	10.18%	31.14	1.37	47.65%	6.50%	54.15%	43.97%	52.16%
1946	2.12%	978.90	-21.10	19.90	-0.12%	32.71	1.48	5.04%	4.75%	9.79%	9.91%	7.67%
1947	2.43%	951.13	-48.87	21.20	-2.77%	25.60	1.58	-21.74%	4.83%	-16.91%	-14.14%	-19.34%
1948	2.37%	1,009.51	9.51	24.30	3.38%	26.20	1.63	2.34%	6.37%	8.71%	5.33%	6.34%
1949	2.09%	1,045.58	45.58	23.70	6.93%	30.57	1.68	16.68%	6.41%	23.09%	16.16%	21.00%
1950	2.24%	975.93	-24.07	20.90	-0.32%	30.81	1.85	0.79%	6.05%	6.84%	7.15%	4.60%
1951	2.69%	930.75	-69.25	22.40	-4.69%	33.85	1.90	9.87%	6.17%	16.03%	20.72%	13.34%
1952	2.79%	984.75	-15.25	26.90	1.17%	37.85	1.92	11.82%	5.67%	17.49%	16.32%	14.70%
1953	2.74%	1,007.66	7.66	27.90	3.56%	39.61	2.09	4.65%	5.52%	10.17%	6.62%	7.43%
1954	2.72%	1,003.07	3.07	27.40	3.05%	47.56	2.14	20.07%	5.40%	25.47%	22.43%	22.75%
1955	2.95%	965.44	-34.56	27.20	-0.74%	49.35	2.27	3.76%	4.77%	8.54%	9.27%	5.59%
1956	3.45%	928.19	-71.81	29.50	-4.23%	48.96	2.37	-0.79%	4.80%	4.01%	8.24%	0.56%
1957	3.23%	1,032.23	32.23	34.50	6.67%	50.30	2.46	2.74%	5.02%	7.76%	1.09%	4.53%
1958	3.82%	918.01	-81.99	32.30	-4.97%	66.37	2.57	31.95%	5.11%	37.06%	42.03%	33.24%
1959	4.47%	914.65	-85.35	38.20	-4.71%	65.77	2.64	-0.90%	3.98%	3.07%	7.79%	-1.40%
1960	3.80%	1,093.27	93.27	44.70	13.80%	76.82	2.74	16.80%	4.17%	20.97%	7.17%	17.17%
1961	4.15%	952.75	-47.25	38.00	-0.92%	99.32	2.86	29.29%	3.72%	33.01%	33.94%	28.86%
1962	3.95%	1,027.48	27.48	41.50	6.90%	96.49	3.07	-2.85%	3.09%	0.24%	-6.66%	-3.71%
1963	4.17%	970.35	-29.65	39.50	0.99%	102.31	3.33	6.03%	3.45%	9.48%	8.50%	5.31%
1964	4.23%	991.96	-8.04	41.70	3.37%	115.54	3.68	12.93%	3.60%	16.53%	13.16%	12.30%
1965	4.50%	964.64	-35.36	42.30	0.69%	114.86	4.02	-0.59%	3.48%	2.89%	2.20%	-1.61%
1966	4.55%	993.48	-6.52	45.00	3.85%	105.99	4.18	-7.72%	3.64%	-4.08%	-7.93%	-8.63%

MOODY'S ELECTRIC UTILITY COMMON STOCKS
OVER LONG-TERM TREASURY BONDS
ANNUAL LONG-TERM RISK PREMIUM ANALYSIS

Year	Long-Term Government Bond Yield (1)	20 year Maturity Bond Value (2)	Gain/Loss (3)	Interest (4)	Bond Total Return (5)	Moody's Electric Utility Stock Index (6)	Dividend (7)	Capital Gain/(Loss) % Growth (8)	Yield (9)	Stock Total Return (10)	Equity Risk Premium (11)	Equity Risk Premium over Yield (12)
1967	5.56%	879.01	-120.99	45.50	-7.55%	98.19	4.44	-7.36%	4.19%	-3.17%	4.38%	-8.73%
1968	5.98%	951.38	-48.62	55.60	0.70%	104.04	4.58	5.96%	4.66%	10.62%	9.92%	4.64%
1969	6.87%	904.00	-96.00	59.80	-3.62%	84.62	4.63	-18.67%	4.45%	-14.22%	-10.60%	-21.09%
1970	6.48%	1,043.38	43.38	68.70	11.21%	88.59	4.73	4.69%	5.59%	10.28%	-0.93%	3.80%
1971	5.97%	1,059.09	59.09	64.80	12.39%	85.56	4.81	-3.42%	5.43%	2.01%	-10.38%	-3.96%
1972	5.99%	997.69	-2.31	59.70	5.74%	83.61	4.92	-2.28%	5.75%	3.47%	-2.27%	-2.52%
1973	7.26%	867.09	-132.91	59.90	-7.30%	60.87	5.04	-27.20%	6.03%	-21.17%	-13.87%	-28.43%
1974	7.60%	965.33	-34.67	72.60	3.79%	41.17	4.83	-32.36%	7.93%	-24.43%	-28.22%	-32.03%
1975	8.05%	955.63	-44.37	76.00	3.16%	55.66	4.99	35.20%	12.12%	47.32%	44.15%	39.27%
1976	7.21%	1,088.25	88.25	80.50	16.87%	66.29	5.25	19.10%	9.43%	28.53%	11.66%	21.32%
1977	8.03%	919.03	-80.97	72.10	-0.89%	68.19	5.68	2.87%	8.57%	11.43%	12.32%	3.40%
1978	8.98%	912.47	-87.53	80.30	-0.72%	59.75	5.98	-12.38%	8.77%	-3.61%	-2.88%	-12.59%
1979	10.12%	902.99	-97.01	89.80	-0.72%	56.41	6.34	-5.59%	10.61%	5.02%	5.74%	-5.10%
1980	11.99%	859.23	-140.77	101.20	-3.96%	54.42	6.67	-3.53%	11.82%	8.30%	12.25%	-3.69%
1981	13.34%	906.45	-93.55	119.90	2.63%	57.20	7.16	5.11%	13.16%	18.27%	15.63%	4.93%
1982	10.95%	1,192.38	192.38	133.40	32.58%	70.26	7.64	22.83%	13.36%	36.19%	3.61%	25.24%
1983	11.97%	923.12	-76.88	109.50	3.26%	72.03	8.00	2.52%	11.39%	13.91%	10.64%	1.94%
1984	11.70%	1,020.70	20.70	119.70	14.04%	80.16	8.37	11.29%	11.62%	22.91%	8.87%	11.21%
1985	9.56%	1,189.27	189.27	117.00	30.63%	94.98	8.71	18.49%	10.87%	29.35%	-1.27%	19.79%
1986	7.89%	1,166.63	166.63	95.60	26.22%	113.66	8.97	19.67%	9.44%	29.11%	2.89%	21.22%
1987	9.20%	881.17	-118.83	78.90	-3.99%	94.24	9.12	-17.09%	8.02%	-9.06%	-5.07%	-18.26%
1988	9.18%	1,001.82	1.82	92.00	9.38%	100.94	8.71	7.11%	9.24%	16.35%	6.97%	7.17%
1989	8.16%	1,099.75	99.75	91.80	19.16%	122.52	8.85	21.38%	8.77%	30.15%	10.99%	21.99%
1990	8.44%	973.17	-26.83	81.60	5.48%	117.77	8.76	-3.88%	7.15%	3.27%	-2.20%	-5.17%
1991	7.30%	1,118.94	118.94	84.40	20.33%	144.02	9.02	22.29%	7.66%	29.95%	9.61%	22.65%
1992	7.26%	1,004.19	4.19	73.00	7.72%	141.06	8.82	-2.06%	6.12%	4.07%	-3.65%	-3.19%
1993	6.54%	1,079.70	79.70	72.60	15.23%	146.70	9.04	4.00%	6.41%	10.41%	-4.82%	3.87%
1994	7.99%	856.40	-143.60	65.40	-7.82%	115.50	9.01	-21.27%	6.14%	-15.13%	-7.31%	-23.12%
1995	6.03%	1,225.98	225.98	79.90	30.59%	142.90	9.06	23.72%	7.84%	31.57%	0.98%	25.54%
1996	6.73%	923.67	-76.33	60.30	-1.60%	136.00	9.06	-4.83%	6.34%	1.51%	3.11%	-5.22%
1997	6.02%	1,081.92	81.92	67.30	14.92%	155.73	9.06	14.51%	6.66%	21.17%	6.25%	15.15%
1998	5.42%	1,072.71	72.71	60.20	13.29%	181.84	8.01	16.77%	5.14%	21.91%	8.62%	16.49%
1999	6.82%	848.41	-151.59	54.20	-9.74%	137.30	8.06	-24.49%	4.43%	-20.06%	-10.32%	-26.88%
2000	5.58%	1,148.30	148.30	68.20	21.65%	227.09	8.71	65.40%	6.34%	71.74%	50.09%	66.16%
2001	5.75%	979.95	-20.05	55.80	3.57%	200.50	8.95	-11.71%	3.94%	-7.77%	-11.34%	-13.52%
2002	4.84%	1,115.77	115.77	57.50	17.33%	169.50	8.83	-15.46%	4.40%	-11.06%	-28.38%	-15.90%

MOODY'S ELECTRIC UTILITY COMMON STOCKS
OVER LONG-TERM TREASURY BONDS
ANNUAL LONG-TERM RISK PREMIUM ANALYSIS

Year	Long-Term Government Bond Yield (1)	20 year Maturity Bond Value (2)	Gain/Loss (3)	Interest (4)	Bond Total Return (5)	Moody's Electric Utility Stock Index (6)	Dividend (7)	Capital Gain/(Loss) % Growth (8)	Yield (9)	Stock Total Return (10)	Equity Risk Premium (11)	Equity Risk Premium over Yield (12)
2003	5.11%	966.42	-33.58	48.40	1.48%			18.99%	3.79%	22.78%	21.30%	17.67%
2004	4.84%	1,034.35	34.35	51.10	8.54%			21.79%	3.39%	25.18%	16.64%	20.34%
2005	4.61%	1,029.84	29.84	48.40	7.82%			13.51%	3.31%	16.82%	9.00%	12.21%
Mean											**5.5%**	**5.6%**

Source: Mergent Public Utility Manual December stock prices and dividends
Dec. Bond yields from Ibbotson Associates 2006 Valuation Yearbook Table B-9 Long-Term Government Bonds Yields

December stock price, dividends from Mergent's Public Utility Manual
2003-2005 data from S&P Elec Utility Index, S&P Analyst Handbook 2005 and monthly suppements

ELECTRIC UTILITIES
HISTORICAL GROWTH RATES

	Company Name (1)	Industry (2)	% Earnings Growth 5-Year (3)	% Dividend Growth 5-Year (4)	% Book Value Growth 5-Year (5)
1	Allegheny Energy	UTILEAST			-7.5
2	ALLETE	UTILCENT			
3	Alliant Energy	UTILCENT	-1.0	-12.5	-2.5
4	Amer. Elec. Power	UTILCENT	3.5	-9.0	-3.5
5	Ameren Corp.	UTILCENT	0.5		5.0
6	Aquila Inc.	UTILCENT			-21.5
7	Avista Corp.	UTILWEST	-3.5	-5.0	4.5
8	Black Hills	UTILWEST		3.5	16.0
9	Cen. Vermont Pub. Serv.	UTILEAST	1.0	0.5	2.5
10	CenterPoint Energy	UTILCENT			
11	CH Energy Group	UTILEAST	-1.5		2.0
12	Cleco Corp.	UTILCENT	1.0	2.0	4.0
13	CMS Energy Corp.	UTILCENT	-27.5		-12.5
14	Consol. Edison	UTILEAST	-2.0	1.0	2.5
15	Constellation Energy	UTILEAST	7.5	-7.0	5.5
16	Dominion Resources	UTILEAST	9.0	0.5	3.5
17	DPL Inc.	UTILCENT	-1.0	0.5	-1.0
18	DTE Energy	UTILCENT	-2.0		3.5
19	Duke Energy	UTILEAST	-6.5	0.5	6.0
20	Duquesne Light Hldgs	UTILEAST	-12.0	-8.5	-14.5
21	Edison Int'l	UTILWEST		-9.0	8.5
22	El Paso Electric	UTILWEST	-4.5		8.5
23	Empire Dist. Elec.	UTILCENT	-5.0		2.0
24	Energy East Corp.	UTILEAST	-2.5	5.0	6.0
25	Entergy Corp.	UTILCENT	10.0	7.5	4.5
26	Exelon Corp.	UTILEAST	11.5		4.0
27	FirstEnergy Corp.	UTILEAST		2.5	6.0
28	Florida Public Utilities	UTILEAST	1.0	4.0	9.5
29	Fortis Inc.	UTILEAST	13.5	4.0	9.0
30	FPL Group	UTILEAST	3.5	4.5	6.0
31	G't Plains Energy	UTILCENT	6.0		1.0
32	Green Mountain Pwr.	UTILEAST		5.0	3.0
33	Hawaiian Elec.	UTILWEST	1.0		3.0
34	IDACORP Inc.	UTILWEST	-11.0	-6.0	3.0
35	KFX Inc	UTILCENT			
36	Maine & Maritimes Corp	UTILEAST	-18.0	2.5	5.0

ELECTRIC UTILITIES
HISTORICAL GROWTH RATES

	Company Name (1)	Industry (2)	% Earnings Growth 5-Year (3)	% Dividend Growth 5-Year (4)	% Book Value Growth 5-Year (5)
37	MDU Resources	UTILWEST	12.5	5.0	12.5
38	MGE Energy	UTILCENT	2.0	1.0	6.5
39	NiSource Inc.	UTILCENT		1.0	7.0
40	Northeast Utilities	UTILEAST		30.5	3.0
41	NSTAR	UTILEAST	4.0	1.0	2.0
42	OGE Energy	UTILCENT	-2.0		1.5
43	Otter Tail Corp.	UTILCENT	2.0	2.0	7.5
44	Pepco Holdings	UTILEAST	-1.0		0.5
45	PG&E Corp.	UTILWEST			1.0
46	Pinnacle West Capital	UTILWEST	-5.0	6.5	4.0
47	PNM Resources	UTILWEST	-1.0	5.0	4.5
48	PPL Corp.	UTILEAST	8.5	8.5	12.0
49	Progress Energy	UTILEAST	4.5	3.0	6.5
50	Public Serv. Enterprise	UTILEAST	2.0	0.5	3.5
51	Puget Energy Inc.	UTILWEST	-7.5	-11.5	0.5
52	Rochester Gas & Electric Corp.	UTILEAST			-2.5
53	SCANA Corp.	UTILEAST	7.0	2.0	3.0
54	Sempra Energy	UTILWEST	16.0	-5.0	10.5
55	Sierra Pacific Res.	UTILWEST			-8.0
56	Southern Co.	UTILEAST	2.0	1.0	-1.0
57	TECO Energy	UTILEAST	-20.0	-8.5	-7.5
58	TXU Corp.	UTILCENT	-4.5	-12.0	-24.0
59	U.S. Energy Sys Inc	UTILEAST			5.0
60	UIL Holdings	UTILEAST	-9.0		2.0
61	UniSource Energy	UTILWEST	5.0		12.0
62	UNITIL Corp.	UTILEAST	-1.5		0.5
63	Vectren Corp.	UTILCENT	4.0	3.5	4.5
64	Westar Energy	UTILCENT	-1.5	-14.5	-11.0
65	Wisconsin Energy	UTILCENT	7.5	-11.0	5.0
66	WPS Resources	UTILCENT	11.0	2.0	8.5
67	Xcel Energy Inc.	UTILWEST	-5.5	-11.0	-4.5
	AVERAGE		**0.0**	**-0.3**	**2.1**

Source: Value Line Investment Analyzer 10/2006

INVESTMENT - GRADE INTEGRATED ELECTRIC UTILITIES
DCF ANALYSIS: VALUE LINE GROWTH PROJECTIONS

	Company	% Current Divid Yield (1)	Proj EPS Growth (2)
1	Alliant Energy	3.3	4.5
2	Ameren Corp.	4.8	1.5
3	CH Energy Group	4.2	3.0
4	Consol. Edison	5.0	3.0
5	DTE Energy	4.9	3.0
6	Energy East Corp.	4.8	4.0
7	Entergy Corp.	2.7	5.0
8	Exelon Corp.	2.8	7.0
9	MGE Energy	4.3	6.5
10	Northeast Utilities	3.3	6.0
11	NSTAR	3.7	6.0
12	Pepco Holdings	4.3	8.5
13	PG&E Corp.	3.3	5.5
14	PNM Resources	3.2	5.5
15	PPL Corp.	3.5	11.0
16	Public Serv. Enterprise	3.8	3.5
17	Puget Energy Inc.	4.3	5.0
18	TECO Energy	4.8	5.4
19	UniSource Energy	2.6	7.0
20	Wisconsin Energy	2.2	6.5
21	Xcel Energy Inc.	4.3	6.0

Notes:
Column 1, 2: Value Line Investment Survey for Windows, 10/2006

TECO Energy growth projection of 18.5% replaced by analysts' growth forecast of 5.4%.

Public Service Enterprise eliminated from sample due to recent merger negotiations.

INVESTMENT - GRADE INTEGRATED ELECTRIC UTILITIES
DCF ANALYSIS: VALUE LINE GROWTH PROJECTIONS

	Company	% Current Divid Yield (1)	Proj EPS Growth (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1	Alliant Energy	3.3	4.5	3.4	7.9	8.1
2	Ameren Corp.	4.8	1.5	4.9	6.4	6.7
3	CH Energy Group	4.2	3.0	4.3	7.3	7.5
4	Consol. Edison	5.0	3.0	5.1	8.1	8.4
5	DTE Energy	4.9	3.0	5.1	8.1	8.3
6	Energy East Corp.	4.8	4.0	5.0	9.0	9.3
7	Entergy Corp.	2.7	5.0	2.8	7.8	8.0
8	Exelon Corp.	2.8	7.0	3.0	10.0	10.2
9	MGE Energy	4.3	6.5	4.6	11.1	11.3
10	Northeast Utilities	3.3	6.0	3.4	9.4	9.6
11	NSTAR	3.7	6.0	4.0	10.0	10.2
12	Pepco Holdings	4.3	8.5	4.7	13.2	13.4
13	PG&E Corp.	3.3	5.5	3.4	8.9	9.1
14	PNM Resources	3.2	5.5	3.4	8.9	9.1
15	PPL Corp.	3.5	11.0	3.8	14.8	15.0
16	Puget Energy Inc.	4.3	5.0	4.5	9.5	9.8
17	TECO Energy	4.8	5.4	5.0	10.4	10.7
18	UniSource Energy	2.6	7.0	2.8	9.8	9.9
19	Wisconsin Energy	2.2	6.5	2.3	8.8	8.9
20	Xcel Energy Inc.	4.3	6.0	4.6	10.6	10.8
	AVERAGE	**3.8**	**5.5**	**4.0**	**9.5**	**9.7**

Notes:
Column 1, 2: Value Line Investment Survey for Windows, 10/2006
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2

INTEGRATED ELECTRIC UTILITIES
DCF ANALYSIS: ANALYSTS' GROWTH FORECASTS

	Company	% Current Divid Yield (1)	Analysts' Growth Forecast (2)
1	Alliant Energy	3.3	4.0
2	Ameren Corp.	4.8	6.1
3	CH Energy Group	4.2	
4	Consol. Edison	5.0	3.7
5	DTE Energy	4.9	4.3
6	Energy East Corp.	4.8	4.5
7	Entergy Corp.	2.7	8.3
8	Exelon Corp.	2.8	10.1
9	MGE Energy	4.3	
10	Northeast Utilities	3.3	8.7
11	NSTAR	3.7	5.5
12	Pepco Holdings	4.3	4.8
13	PG&E Corp.	3.3	7.8
14	PNM Resources	3.2	8.3
15	PPL Corp.	3.5	9.2
16	Public Serv. Enterprise	3.8	9.0
17	Puget Energy Inc.	4.3	7.0
18	TECO Energy	4.8	5.4
19	UniSource Energy	2.6	
20	Wisconsin Energy	2.2	7.4
21	Xcel Energy Inc.	4.3	4.3

Notes:
Column 1: Value Line Investment Survey for Windows, 10/2006
Column 2: Zacks long-term earnings growth forecast, 10/2006

CH Energy, MGE Energy, and UniSource were eliminated from sample because no growth forecast was available.

Public Service Enterprise eliminated from sample due to recent merger negotiations.

INTEGRATED ELECTRIC UTILITIES
DCF ANALYSIS: ANALYSTS' GROWTH FORECASTS

	Company	% Current Divid Yield (1)	Analysts' Growth Forecast (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1	Alliant Energy	3.3	4.0	3.4	7.4	7.6
2	Ameren Corp.	4.8	6.1	5.1	11.2	11.5
3	Consol. Edison	5.0	3.7	5.1	8.8	9.1
4	DTE Energy	4.9	4.3	5.1	9.5	9.7
5	Energy East Corp.	4.8	4.5	5.0	9.5	9.8
6	Entergy Corp.	2.7	8.3	2.9	11.2	11.4
7	Exelon Corp.	2.8	10.1	3.1	13.2	13.3
8	Northeast Utilities	3.3	8.7	3.5	12.2	12.4
9	NSTAR	3.7	5.5	3.9	9.4	9.7
10	Pepco Holdings	4.3	4.8	4.5	9.3	9.6
11	PG&E Corp.	3.3	7.8	3.5	11.3	11.5
12	PNM Resources	3.2	8.3	3.5	11.7	11.9
13	PPL Corp.	3.5	9.2	3.8	13.0	13.2
14	Puget Energy Inc.	4.3	7.0	4.6	11.6	11.9
15	TECO Energy	4.8	5.4	5.0	10.4	10.7
16	Wisconsin Energy	2.2	7.4	2.3	9.7	9.8
17	Xcel Energy Inc.	4.3	4.3	4.5	8.8	9.1
	AVERAGE	**3.8**	**6.4**	**4.1**	**10.5**	**10.7**

Notes:
Column 1: Value Line Investment Survey for Windows, 10/2006
Column 2: Zacks long-term earnings growth forecast, 10/2006
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2

MOODY'S ELECTRIC UTILITIES
DCF ANALYSIS: VALUE LINE GROWTH PROJECTIONS

	Company	% Current Divid Yield (1)	Proj EPS Growth (2)
1	Amer. Elec. Power	4.4	2.5
2	CH Energy Group	4.4	3.5
3	Consol. Edison	5.2	2.5
4	Constellation Energy	2.7	13.5
5	Dominion Resources	4.0	8.0
6	DPL Inc.	3.6	5.5
7	Duquesne Light Hldgs	5.9	4.0
8	Duke Energy	4.3	8.5
9	Energy East Corp.	4.8	4.0
10	Exelon Corp.	3.1	7.0
11	FirstEnergy Corp.	3.6	8.5
12	IDACORP Inc.	3.7	4.5
13	NiSource Inc.	4.5	3.5
14	OGE Energy	4.5	4.0
15	PPL Corp.	3.7	8.0
16	Progress Energy	5.5	
17	Public Serv. Enterprise	3.5	1.5
18	Southern Co.	4.7	5.0
19	TECO Energy	4.6	8.5
20	Xcel Energy Inc.	4.8	7.5

Notes:
Column 1, 2: Value Line Investment Analyzer, 10/2006

No Value Line growth forecasts available for Progress Energy.

Public Service Enterprise eliminated from sample due to recent merger negotiations.

MOODY'S ELECTRIC UTILITIES
DCF ANALYSIS: VALUE LINE GROWTH PROJECTIONS

	Company	% Current Divid Yield (1)	Proj EPS Growth (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1	Amer. Elec. Power	4.4	2.5	4.5	7.0	7.2
2	CH Energy Group	4.4	3.5	4.6	8.1	8.3
3	Consol. Edison	5.2	2.5	5.3	7.8	8.1
4	Constellation Energy	2.7	13.5	3.1	16.6	16.8
5	Dominion Resources	4.0	8.0	4.3	12.3	12.5
6	DPL Inc.	3.6	5.5	3.8	9.3	9.5
7	Duquesne Light Hldgs	5.9	4.0	6.1	10.1	10.5
8	Duke Energy	4.3	8.5	4.7	13.2	13.4
9	Energy East Corp.	4.8	4.0	5.0	9.0	9.3
10	Exelon Corp.	3.1	7.0	3.3	10.3	10.5
11	FirstEnergy Corp.	3.6	8.5	3.9	12.4	12.6
12	IDACORP Inc.	3.7	4.5	3.9	8.4	8.6
13	NiSource Inc.	4.5	3.5	4.6	8.1	8.4
14	OGE Energy	4.5	4.0	4.7	8.7	8.9
15	PPL Corp.	3.7	8.0	4.0	12.0	12.2
16	Southern Co.	4.7	5.0	4.9	9.9	10.2
17	TECO Energy	4.6	8.5	5.0	13.5	13.8
18	Xcel Energy Inc.	4.8	7.5	5.2	12.7	12.9
	AVERAGE	**4.3**	**6.0**	**4.5**	**10.5**	**10.8**

Notes:
Column 1, 2: Value Line Investment Survey for Windows, 10/2006
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2

MOODY'S ELECTRIC UTILITIES
DCF ANALYSIS: ANALYSTS' GROWTH FORECASTS

	Company	% Current Divid Yield (1)	Analysts' Growth Forecast (2)
1	Amer. Elec. Power	4.4	3.0
2	CH Energy Group	4.4	
3	Consol. Edison	5.2	4.2
4	Constellation Energy	2.7	11.0
5	Dominion Resources	4.0	9.0
6	DPL Inc.	3.6	7.0
7	Duquesne Light Hldgs	5.9	
8	Duke Energy	4.3	6.0
9	Energy East Corp.	4.8	4.5
10	Exelon Corp.	3.1	9.4
11	FirstEnergy Corp.	3.6	4.8
12	IDACORP Inc.	3.7	4.5
13	NiSource Inc.	4.5	3.4
14	OGE Energy	4.5	3.0
15	PPL Corp.	3.7	8.3
16	Progress Energy	5.5	3.8
17	Public Serv. Enterprise	3.5	7.8
18	Southern Co.	4.7	4.8
19	TECO Energy	4.6	5.7
20	Xcel Energy Inc.	4.8	4.2

Notes:
Column 1: Value Line Investment Analyzer, 10/2006
Column 2: Zacks long-term earnings growth forecast, 10/2006

CH Energy Group and Duquesne Light were eliminated from sample because no growth forecast was available.

Public Service Enterprise eliminated from sample due to recent merger negotiations.

MOODY'S ELECTRIC UTILITIES
DCF ANALYSIS: ANALYSTS' GROWTH FORECASTS

	Company	% Current Divid Yield (1)	Analysts' Growth Forecast (2)	% Expected Divid Yield (3)	Cost of Equity (4)	ROE (5)
1	Amer. Elec. Power	4.4	3.0	4.5	7.5	7.7
2	Consol. Edison	5.2	4.2	5.4	9.6	9.9
3	Constellation Energy	2.7	11.0	3.0	14.0	14.2
4	Dominion Resources	4.0	9.0	4.3	13.3	13.5
5	DPL Inc.	3.6	7.0	3.9	10.9	11.1
6	Duke Energy	4.3	6.0	4.6	10.6	10.8
7	Energy East Corp.	4.8	4.5	5.0	9.5	9.8
8	Exelon Corp.	3.1	9.4	3.4	12.8	13.0
9	FirstEnergy Corp.	3.6	4.8	3.8	8.6	8.8
10	IDACORP Inc.	3.7	4.5	3.9	8.4	8.6
11	NiSource Inc.	4.5	3.4	4.6	8.1	8.3
12	OGE Energy	4.5	3.0	4.6	7.6	7.9
13	PPL Corp.	3.7	8.3	4.0	12.3	12.5
14	Progress Energy	5.5	3.8	5.7	9.4	9.7
15	Southern Co.	4.7	4.8	4.9	9.6	9.9
16	TECO Energy	4.6	5.7	4.9	10.6	10.8
17	Xcel Energy Inc.	4.8	4.2	5.0	9.2	9.4
	AVERAGE	**4.2**	**5.7**	**4.4**	**10.1**	**10.4**

Notes:

Column 1: Value Line Investment Analyzer, 10/2006
Column 2: Zacks long-term earnings growth forecast, 10/2006
Column 3 = Column 1 times (1 + Column 2/100)
Column 4 = Column 3 + Column 2
Column 5 = (Column 3 /0.95) + Column 2

APPENDIX A

CAPM, EMPIRICAL CAPM

The Capital Asset Pricing Model (CAPM) is a fundamental paradigm of finance. Simply put, the fundamental idea underlying the CAPM is that risk-averse investors demand higher returns for assuming additional risk, and higher-risk securities are priced to yield higher expected returns than lower-risk securities. The CAPM quantifies the additional return, or risk premium, required for bearing incremental risk. It provides a formal risk-return relationship anchored on the basic idea that only market risk matters, as measured by beta. According to the CAPM, securities are priced such that their:

EXPECTED RETURN = RISK-FREE RATE + RISK PREMIUM

Denoting the risk-free rate by R_F and the return on the market as a whole by R_M, the CAPM is:

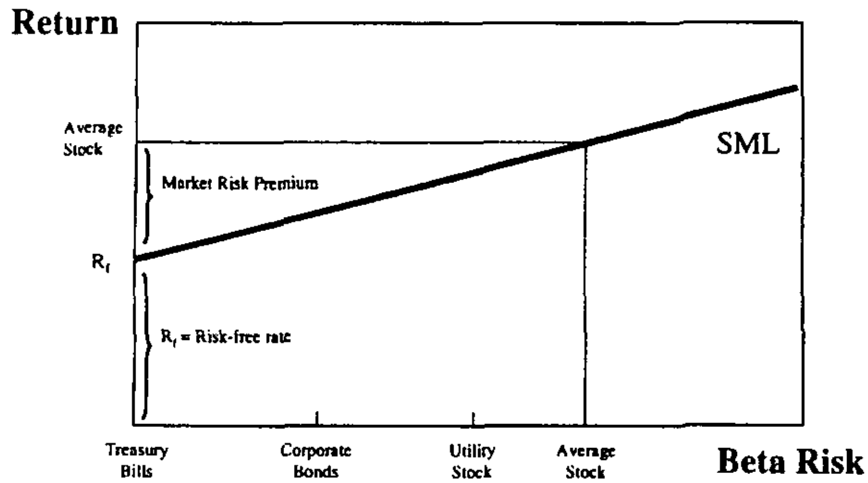
$$K = R_F + \beta(R_M - R_F) \qquad (1)$$

Equation 1 is the CAPM expression which asserts that an investor expects to earn a return, K, that could be gained on a risk-free investment, R_F, plus a risk premium for assuming risk, proportional to the security's market risk, also known as beta, β, and the market risk premium, $(R_M - R_F)$, where R_M is the market return . The market risk premium $(R_M - R_F)$ can be abbreviated MRP so that the CAPM becomes:

$$K = R_F + \beta \times MRP \qquad (2)$$

The CAPM risk-return relationship is depicted in the figure below and is typically labeled as the Security Market Line (SML) by the investment community.

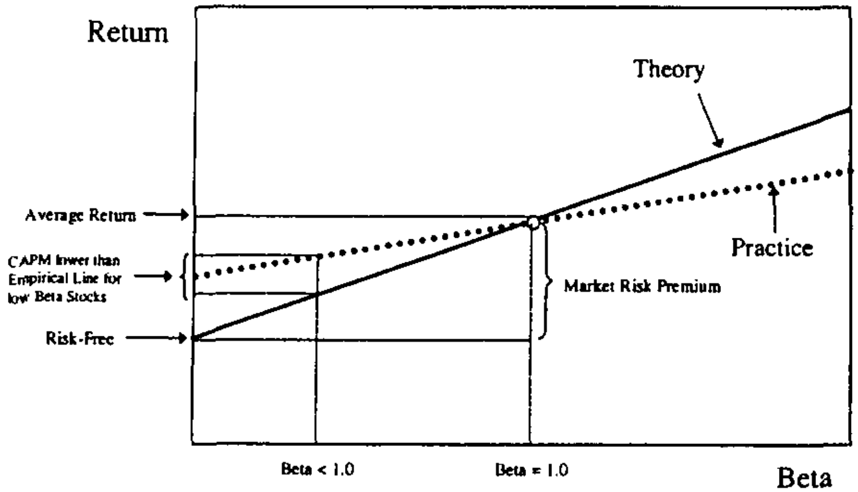
CAPM and Risk - Return in Capital Markets



A myriad empirical tests of the CAPM have shown that the risk-return tradeoff is not as steeply sloped as that predicted by the CAPM, however. That is, low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. In other words, the CAPM tends to overstate the actual sensitivity of the cost of capital to beta: low-beta stocks tend to have higher returns and high-beta stocks tend to have lower risk returns than predicted by the CAPM. The difference between the CAPM and the type of relationship observed in the empirical studies is depicted in the figure below. This is one of the most widely known empirical findings of the finance literature. This extensive literature is summarized in Chapter 13 of Dr. Morin's book [Regulatory Finance, Public Utilities Report Inc., Arlington, VA, 1994].

Risk vs Return

Theory vs. Practice



A number of refinements and expanded versions of the original CAPM theory have been proposed to explain the empirical findings. These revised CAPMs typically produce a risk-return relationship that is flatter than the standard CAPM prediction. The following equation makes use of these empirical findings by flattening the slope of the risk-return relationship and increasing the intercept:

$$K = R_F + \alpha + \beta \, (MRP - \alpha) \qquad (3)$$

where α is the "alpha" of the risk-return line, a constant determined empirically, and the other symbols are defined as before. Alternatively, Equation 3 can be written as follows:

$$K = R_F + a\,MRP + (1\text{-}a)\,\beta\,MRP \qquad (4)$$

where a is a fraction to be determined empirically. Comparing Equations 3 and 4, it is easy to see that alpha equals 'a' times MRP, that is, $\alpha = a \times MRP$

Theoretical Underpinnings

The obvious question becomes what would produce a risk return relationship which is flatter than the CAPM prediction, or in other words, how do you explain the presence of "alpha" in the above equation. The exclusion of variables aside from beta would produce this result. Three such variables are noteworthy: dividend yield, skewness, and hedging potential.

The dividend yield effects stem from the differential taxation on corporate dividends and capital gains. The standard CAPM does not consider the regularity of dividends received by investors. Utilities generally maintain high dividend payout ratios relative to the market, and by ignoring dividend yield, the CAPM provides biased cost of capital estimates. To the extent that dividend income is taxed at a higher rate than capital gains, investors will require higher pre-tax returns in order to equalize the after-tax returns provided by high-yielding stocks (e.g. utility stocks) with those of low-yielding stocks. In other words, high-yielding stocks must offer investors higher pre-tax returns. Even if dividends and capital gains are undifferentiated for tax purposes, there is still a tax bias in favor of earnings retention (lower dividend payout), as capital gains taxes are paid only when gains are realized.

Empirical studies by Litzenberger and Ramaswamy (1979), Litzenberger et al. (1980) and Rosenberg and Marathe (1975) find that security returns are positively related to dividend yield as well as to beta. These results are consistent with after-tax extensions of the CAPM developed by Breenan (1973) and Litzenberger and Ramaswamy (1979) and suggest that the relationship between return, beta, and dividend yield should be estimated and employed to calculate the cost of equity capital.

As far as skewness is concerned, investors are more concerned with losing money than with total variability of return. If risk is defined as the probability of loss, it appears more logical to measure risk as the probability of achieving a return which is below the expected return. The traditional CAPM provides downward-biased estimates of cost of capital to the extent that these skewness effects are significant. As shown by Kraus and Litzenberger (1976), expected return depends on both on a stock's systematic risk (beta) and the systematic skewness. Empirical studies by Kraus and Litzenberger (1976), Friend, Westerfield, and Granito (1978), and Morin (1981) found that, in addition to beta, skewness of returns has a significant negative relationship with security returns. This result is consistent with the skewness version of the CAPM developed by Rubinstein (1973) and Kraus and Litzenberger (1976).

This is particularly relevant for public utilities whose future profitability is constrained by the regulatory process on the upside and relatively unconstrained on the downside in the face of socio-political realities of public utility regulation. The process of regulation, by restricting the upward potential for returns and responding sluggishly on the downward side, may impart some asymmetry to the distribution of returns, and is more likely to result in utilities earning less, rather than more, than their cost of capital. The traditional CAPM provides downward-biased estimates of cost of capital to the extent that these skewness effects are significant.

As far as hedging potential is concerned, investors are exposed to another kind of risk, namely, the risk of unfavorable shifts in the investment opportunity set. Merton (1973) shows that investors will hold portfolios consisting of three funds: the risk-free asset, the market portfolio, and a portfolio whose returns are perfectly negatively correlated with the riskless asset so as to hedge against unforeseen changes in the future risk-free rate. The higher the degree of protection offered by an asset against unforeseen changes in interest rates, the lower the required return, and conversely. Merton argues that low beta assets, like utility stocks, offer little protection against changes in interest rates, and require higher returns than suggested by the standard CAPM.

Another explanation for the CAPM's inability to fully explain the process determining security returns involves the use of an inadequate or incomplete market index. Empirical studies to validate the CAPM invariably rely on some stock market index as a proxy for the true market portfolio. The exclusion of several asset categories from the definition of market index mis-specifies the CAPM and biases the results found using only stock market data. Kolbe and Read (1983) illustrate the biases in beta estimates which result from applying the CAPM to public utilities. Unfortunately, no comprehensive and easily accessible data exist for several classes of assets, such as mortgages and business investments, so that the exact relation between return and stock betas predicted by the CAPM does not exist. This suggests that the empirical relationship between returns and stock betas is best estimated empirically (ECAPM) rather than by relying on theoretical and elegant CAPM models expanded to include missing assets effects. In any event, stock betas may be highly correlated with the true beta measured with the true market index.

Yet another explanation for the CAPM's inability to fully explain the observed risk-return tradeoff involves the possibility of constraints on investor borrowing that run counter to the assumptions of the CAPM. In response to this inadequacy, several versions of the CAPM have been developed by researchers. One of these versions is the so-called zero-beta, or two-factor, CAPM which provides for a risk-free return in a market where borrowing and lending rates are divergent. If borrowing rates and lending rates differ, or there is no risk-free borrowing or lending, or there is risk-free lending but no risk-free borrowing, then the CAPM has the following form:

$$K = R_Z + \beta(R_m - R_F)$$

The model, christened the zero-beta model, is analogous to the standard CAPM, but with the return on a minimum risk portfolio which is unrelated to market returns, R_Z, replacing the risk-free rate, R_F. The model has been empirically tested by Black, Jensen, and Scholes (1972), who found a flatter than predicted CAPM, consistent with the model and other researchers' findings.

The zero-beta CAPM cannot be literally employed in cost of capital projections, since the zero-beta portfolio is a statistical construct difficult to replicate.

Empirical Evidence

A summary of the empirical evidence on the magnitude of alpha is provided in the table below.

Empirical Evidence on the Alpha Factor		
Author	**Range of alpha**	**Period relied upon**
Fischer (1993)	-3.6% to 3.6%	1931-1991
Fischer, Jensen and Scholes (1972)	-9.61% to 12.24%	1931-1965
Fama and McBeth (1972)	4.08% to 9.36%	1935-1968
Fama and French (1992)	10.08% to 13.56%	1941-1990
Litzenberger and Ramaswamy (1979)	5.32% to 8.17%	
Litzenberger, Ramaswamy and Sosin (1980)	1.63% to 5.04%	1926-1978
Pettengill, Sundaram and Mathur (1995)	4.6%	
Morin (1994)	2.0%	1926-1984
Harris, Marston, Mishra, and O'Brien	2.0%	1983-1998

Given the observed magnitude of alpha, the empirical evidence indicates that the risk-return relationship is flatter than that predicted by the CAPM. Typical of the empirical evidence is the findings cited in Morin (1994) over the period 1926-1984 indicating that the observed expected return on a security is related to its risk by the following equation:

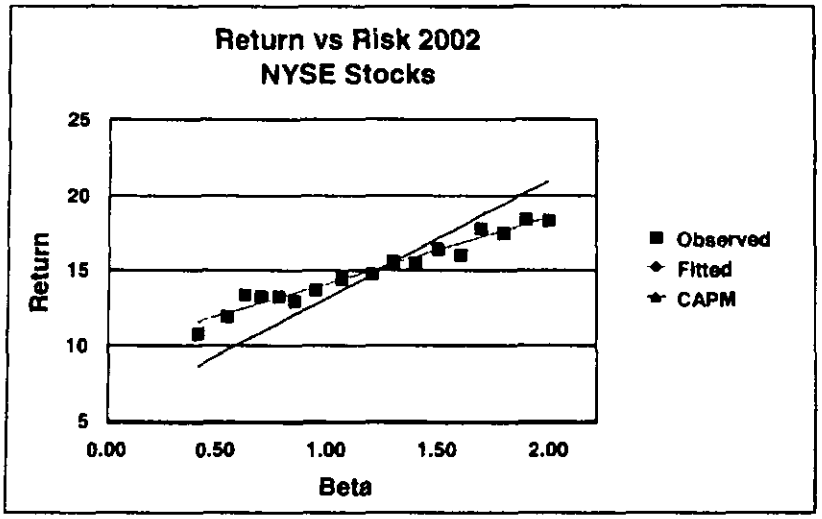
$$K = .0829 + .0520\,\beta$$

Given that the risk-free rate over the estimation period was approximately 6%, this relationship implies that the intercept of the risk-return relationship is higher than the 6% risk-free rate, contrary to the CAPM's prediction. Given that the average return on an average risk stock exceeded the risk-free rate by about 8.0% in that period, that is, the market risk premium $(R_M - R_F) = 8\%$, the intercept of the observed relationship between return and beta exceeds the risk-free rate by about 2%, suggesting an alpha factor of 2%.

Most of the empirical studies cited in the above table utilize raw betas rather than Value Line adjusted betas because the latter were not available over most of the time periods covered in these studies. A study of the relationship between return and adjusted beta is reported on Table

6-7 in Ibbotson Associates Valuation Yearbook 2001. If we exclude the portfolio of very small cap stocks from the relationship due to significant size effects, the relationship between the arithmetic mean return and beta for the remaining portfolios is flatter than predicted and the intercept slightly higher than predicted by the CAPM, as shown on the graph below. It is noteworthy that the Ibbotson study relies on adjusted betas as stated on page 95 of the aforementioned study.

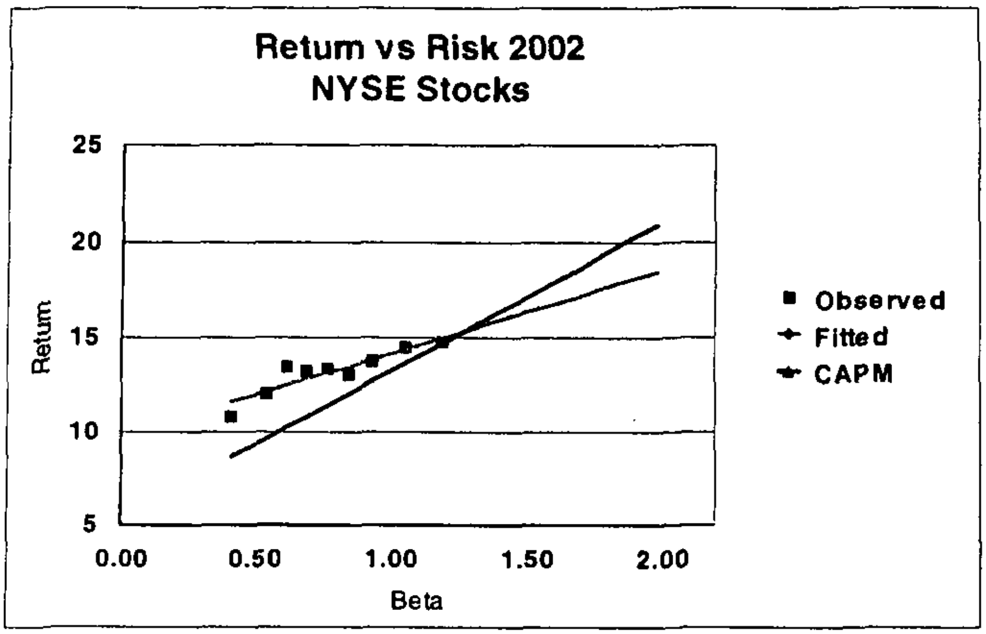
CAPM vs ECAPM



Another study by Morin in May 2002 provides empirical support for the ECAPM. All the stocks covered in the Value Line Investment Survey for Windows for which betas and returns data were available were retained for analysis. There were nearly 2000 such stocks. The expected return was measured as the total shareholder return ("TSR") reported by Value Line over the past ten years. The Value Line adjusted beta was also retrieved from the same data base. The nearly 2000 companies for which all data were available were ranked in ascending order of beta, from lowest to highest. In order to palliate measurement error, the nearly 2000 securities were grouped into ten portfolios of approximately 180 securities for each portfolio. The average returns and betas for each portfolio were as follows:

Portfolio #	Beta	Return
portfolio 1	0.41	10.87
portfolio 2	0.54	12.02
portfolio 3	0.62	13.50
portfolio 4	0.69	13.30
portfolio 5	0.77	13.39
portfolio 6	0.85	13.07
portfolio 7	0.94	13.75
portfolio 8	1.06	14.53
portfolio 9	1.19	14.78
portfolio 10	1.48	20.78

It is clear from the graph below that the observed relationship between DCF returns and Value Line adjusted betas is flatter than that predicted by the plain vanilla CAPM. The observed intercept is higher than the prevailing risk-free rate of 5.7% while the slope is less than equal to the market risk premium of 7.7% predicted by the plain vanilla CAPM for that period.



In an article published in Financial Management, Harris, Marston, Mishra, and O'Brien ("HMMO") estimate ex ante expected returns for S&P 500 companies over the period 1983-

1998[1]. HMMO measure the expected rate of return (cost of equity) of each dividend-paying stock in the S&P 500 for each month from January 1983 to August 1998 by using the constant growth DCF model. They then investigate the relation between the risk premium (expected return over the 20-year Treasury bond yield) estimates for each month to equity betas as of that same month (5-year raw betas).

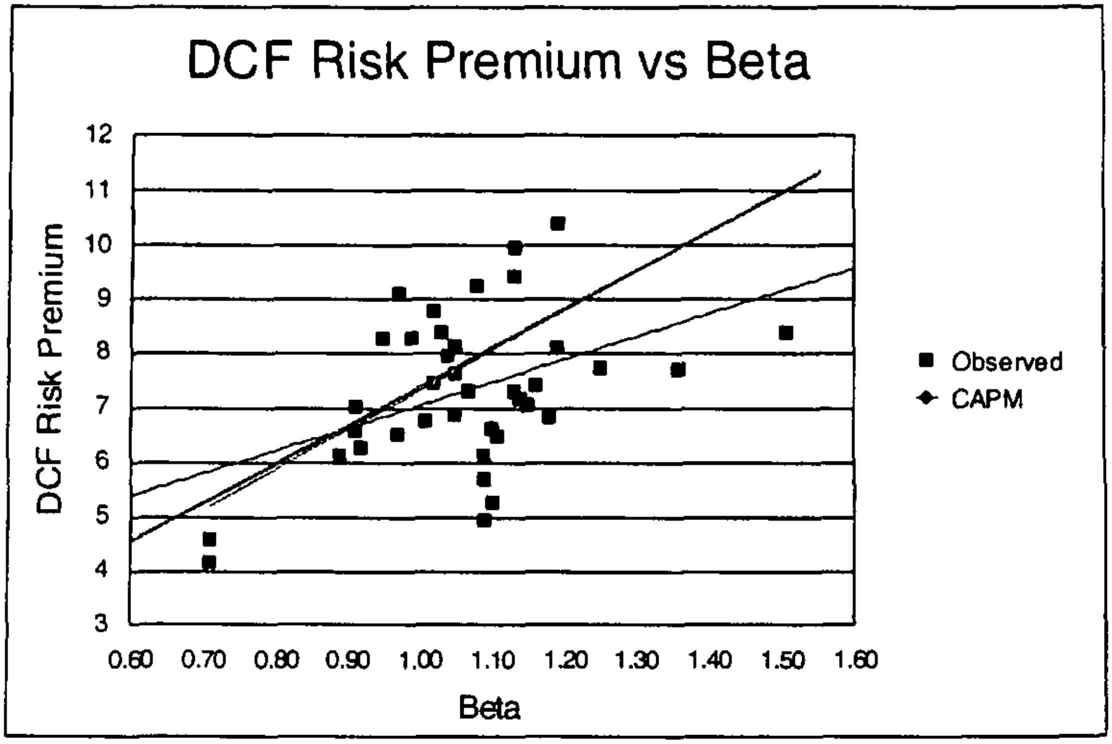
The table below, drawn from HMMO Table 4, displays the average estimate prospective risk premium (Column 2) by industry and the corresponding beta estimate for that industry, both in raw form (Column 3) and adjusted form (Column 4). The latter were calculated with the traditional Value Line – Merrill Lynch – Bloomberg adjustment methodology by giving 1/3 weight of to a beta estimate of 1.00 and 2/3 weight to the raw beta estimate.

[1] Harris, R. S., Marston, F. C., Mishra, D. R., and O'Brien, T. J., "*Ex Ante* Cost of Equity Estimates of S&P 500 Firms: The Choice Between Global and Domestic CAPM," Financial Management, Autumn 2003, pp. 51-66.

Table A-1 Risk Premium and Beta Estimates by Industry

Industry (1)	DCF Risk Premium (2)	Raw Industry Beta (3)	Adjusted Industry Beta (4)
1 Aero	6.63	1.15	1.10
2 Autos	5.29	1.15	1.10
3 Banks	7.16	1.21	1.14
4 Beer	6.60	0.87	0.91
5 BldMat	6.84	1.27	1.18
6 Books	7.64	1.07	1.05
7 Boxes	8.39	1.04	1.03
8 BusSv	8.15	1.07	1.05
9 Chems	6.49	1.16	1.11
10 Chips	8.11	1.28	1.19
11 Clths	7.74	1.37	1.25
12 Cnstr	7.70	1.54	1.36
13 Comps	9.42	1.19	1.13
14 Drugs	8.29	0.99	0.99
15 ElcEq	6.89	1.08	1.05
16 Energy	6.29	0.88	0.92
17 Fin	8.38	1.76	1.51
18 Food	7.02	0.86	0.91
19 Fun	9.98	1.19	1.13
20 Gold	4.59	0.57	0.71
21 Hlth	10.40	1.29	1.19
22 Hsld	6.77	1.02	1.01
23 Insur	7.46	1.03	1.02
24 LabEq	7.31	1.10	1.07
25 Mach	7.32	1.20	1.13
26 Meals	7.98	1.06	1.04
27 MedEq	8.80	1.03	1.02
28 Pap	6.14	1.13	1.09
29 PerSv	9.12	0.95	0.97
30 Retail	9.27	1.12	1.08
31 Rubber	7.06	1.22	1.15
32 Ships	1.95	0.95	0.97
33 Stee	4.96	1.13	1.09
34 Telc	6.12	0.83	0.89
35 Toys	7.42	1.24	1.16
36 Trans	5.70	1.14	1.09
37 Txtls	6.52	0.95	0.97
38 Util	4.15	0.57	0.71
39 Whlsl	8.29	0.92	0.95
MEAN	**7.19**		

The observed statistical relationship between expected return and **adjusted beta** is shown in the graph below along with the CAPM prediction:



If the plain vanilla version of the CAPM is correct, then the intercept of the graph should be zero, recalling that the vertical axis represents returns in excess of the risk-free rate. Instead, the observed intercept is approximately 2%, that is approximately equal to 25% of the expected market risk premium of 7.2% shown at the bottom of Column 2 over the 1983-1998 period, as predicted by the ECAPM. The same is true for the slope of the graph. If the plain vanilla version of the CAPM is correct, then the slope of the relationship should equal the market risk premium of 7.2%. Instead, the observed slope of close to 5% is approximately equal to 75% of the expected market risk premium of 7.2%, as predicted by the ECAPM.

In short, the HMMO empirical findings are quite consistent with the predictions of the ECAPM.

Practical Implementation of the ECAPM

The empirical evidence reviewed above suggests that the expected return on a security is related to its risk by the following relationship:

$$K = R_F + \alpha + \beta\ (MRP - \alpha) \qquad (5)$$

or, alternatively by the following equivalent relationship:

$$K = R_F + a\,MRP + (1-a)\,\beta\,MRP \qquad (6)$$

The empirical findings support values of α from approximately 2% to 7%. If one is using the short-term U.S. Treasury Bills yield as a proxy for the risk-free rate, and given that utility stocks have lower than average betas, an alpha in the lower range of the empirical findings, 2% - 3% is reasonable, albeit conservative.

Using the long-term U.S. Treasury yield as a proxy for the risk-free rate, a lower alpha adjustment is indicated. This is because the use of the long-term U.S. Treasury yield as a proxy for the risk-free rate partially incorporates the desired effect of using the ECAPM[2]. An alpha in the range of 1% - 2% is therefore reasonable.

To illustrate, consider a utility with a beta of 0.80. The risk-free rate is 5%, the MRP is 7%, and the alpha factor is 2%. The cost of capital is determined as follows:

$$K = R_F + \alpha + \beta\ (MRP - \alpha)$$
$$K = 5\% + 2\% + 0.80(7\% - 2\%)$$
$$= 11\%$$

A practical alternative is to rely on the second variation of the ECAPM:

$$K = R_F + a\,MRP + (1-a)\,\beta\,MRP$$

[2] The Security Market Line (SML) using the long-term risk-free rate has a higher intercept and a flatter slope than the SML using the short-term risk-free rate

With an alpha of 2%, a MRP in the 6% - 8% range, the 'a" coefficient is 0.25, and the ECAPM becomes[3]:

$$K = R_F + 0.25\ MRP + 0.75\ \beta\ MRP$$

Returning to the numerical example, the utility's cost of capital is:

$$K = 5\% + 0.25 \times 7\% + 0.75 \times 0.80 \times 7\%$$
$$= 11\%$$

For reasonable values of beta and the MRP, both renditions of the ECAPM produce results that are virtually identical[4].

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[3] Recall that alpha equals 'a' times MRP, that is, alpha = a MRP, and therefore a = alpha/MRP. If alpha is 2%, then a = 0.25

[4] In the Morin (1994) study, the value of "a" was actually derived by systematically varying the constant "a" in equation 6 from 0 to 1 in steps of 0.05 and choosing that value of 'a' that minimized the mean square error between the observed relationship between return and beta:

$$K = 0.0829 + .0520\ \beta$$

The value of a that best explained the observed relationship was 0.25.

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APPENDIX B

FLOTATION COST ALLOWANCE

To obtain the final cost of equity financing from the investors' expected rate of return, it is necessary to make allowance for underpricing, which is the sum of market pressure, costs of flotation, and underwriting fees associated with new issues. Allowance for market pressure should be made because large blocks of new stock may cause significant pressure on market prices even in stable markets. Allowance must also be made for company costs of flotation (including such items as printing, legal and accounting expenses) and for underwriting fees.

1. MAGNITUDE OF FLOTATION COSTS

According to empirical studies, underwriting costs and expenses average at least 4% of gross proceeds for utility stock offerings in the U.S. (See Logue & Jarrow: "Negotiations vs. Competitive Bidding in the Sale of Securities by Public Utilities", Financial Management, Fall 1978.) A study of 641 common stock issues by 95 electric utilities identified a flotation cost allowance of 5.0%. (See Borum & Malley: "Total Flotation Cost for Electric Company Equity Issues", Public Utilities Fortnightly, Feb. 20, 1986.)

Empirical studies suggest an allowance of 1% for market pressure in U.S. studies. Logue and Jarrow found that the absolute magnitude of the relative price decline due to market pressure was less than 1.5%. Bowyer and Yawitz examined 278 public utility stock issues and found an average market pressure of 0.72%. (See Bowyer & Yawitz, "The Effect of New Equity Issues on Utility Stock Prices", Public Utilities Fortnightly, May 22, 1980.)

Eckbo & Masulis ("Rights vs. Underwritten Stock Offerings: An Empirical Analysis", University of British Columbia, Working Paper No. 1208, Sept., 1987) found an average flotation cost of 4.175% for utility common stock offerings. Moreover, flotation costs increased progressively for smaller size issues. They also found that the relative price decline due to market pressure in the days surrounding the announcement amounted to slightly more than 1.5%.

In a classic and monumental study published in the prestigious Journal of Financial Economics by a prominent scholar, a market pressure effect of 3.14% for industrial stock issues and 0.75% for utility common stock issues was found (see Smith, C.W., "Investment Banking and the Capital Acquisition Process," Journal of Financial Economics 15, 1986). Other studies of market pressure are reported in Logue ("On the Pricing of Unseasoned Equity Offerings, Journal of Financial and Quantitative Analysis, Jan. 1973), Pettway ("The Effects of New Equity Sales Upon Utility Share Prices," Public Utilities Fortnightly, May 10 1984), and Reilly and Hatfield ("Investor Experience with New Stock Issues," Financial Analysts' Journal, Sept.- Oct. 1969). In the Pettway study, the market pressure effect for a sample of 368 public utility equity sales was in the range of 2% to 3%. Adding the direct and indirect effects of utility common stock issues, the indicated total flotation cost allowance is above 5.0%, corroborating the results of earlier studies.

As shown in the table below, a comprehensive empirical study by Lee, Lochhead, Ritter, and Zhao, "The Costs of Raising Capital," Journal of Financial Research, Vol. XIX, NO. 1, Spring 1996, shows average direct flotation costs for equity offerings of 3.5% - 5% for stock issues between \$60 and \$500 million. Allowing for market pressure costs raises the flotation cost allowance to well above 5%.

FLOTATION COSTS: RAISING EXTERNAL CAPITAL

(Percent of Total Capital Raised)

Amount Raised in $ Millions	Average Flotation Cost: Common Stock	Average Flotation Cost: New Debt
$ 2 - 9.99	13.28%	4.39%
10 - 19.99	8.72	2.76
20 - 39.99	6.93	2.42
40 - 59.99	5.87	1.32
60 - 79.99	5.18	2.34
80 - 99.99	4.73	2.16
100 - 199.99	4.22	2.31
200 - 499.99	3.47	2.19
500 and Up	3.15	1.64

Note: Flotation costs for IPOs are about 17 percent of the value of common stock issued if the amount raised is less than $10 million and about 6 percent if more than $500 million is raised. Flotation costs are somewhat lower for utilities than others.

Source: Lee, Inmoo, Scott Lochhead, Jay Ritter, and Quanshui Zhao, "The Costs of Raising Capital," *The Journal of Financial Research*, Spring 1996.

Therefore, based on empirical studies, total flotation costs including market pressure amount to approximately 5% of gross proceeds. I have therefore assumed a 5% gross total flotation cost allowance in my cost of capital analyses.

2. APPLICATION OF THE FLOTATION COST ADJUSTMENT

The section below shows: 1) why it is necessary to apply an allowance of 5% to the dividend yield component of equity cost by dividing that yield by 0.95 (100% - 5%) to obtain the fair return on equity capital, and 2) why the flotation adjustment is permanently required to avoid confiscation even if no further stock issues are contemplated. Flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years.

Flotation costs are just as real as costs incurred to build utility plant. Fair regulatory treatment absolutely must permit the recovery of these costs. An analogy with bond issues is useful to understand the treatment of flotation costs in the case of common stocks.

In the case of a bond issue, flotation costs are not expensed but are rather amortized over the life of the bond, and the annual amortization charge is embedded in the cost of service. This is analogous to the process of depreciation, which allows the recovery of funds invested in utility plant. The recovery of bond flotation expense continues year after year, irrespective of whether the company issues new debt capital in the future, until recovery is complete. In the case of common stock that has no finite life, flotation costs are not amortized. Therefore, the recovery of flotation cost requires an upward adjustment to the allowed return on equity. Roger A. Morin, Regulatory Finance, Public Utilities Reports Inc., Arlington, Va., 1994, provides numerical illustrations that show that even if a utility does not contemplate any additional common stock issues, a flotation cost adjustment is still permanently required. Examples there also demonstrate that the allowance applies to retained earnings as well as to the original capital.

From the standard DCF model, the investor's required return on equity capital is expressed as:

$$K = D_1/P_0 + g$$

If P_0 is regarded as the proceeds per share actually received by the company from which dividends and earnings will be generated, that is, P_0 equals B_0, the book value per share, then the company's required return is:

$$r = D_1/B_0 + g$$

Denoting the percentage flotation costs 'f', proceeds per share B_0 are related to market price P_0 as follows:

$$P - fP = B_0$$

$$P(1 - f) = B_0$$

Substituting the latter equation into the above expression for return on equity, we obtain:

$$r = D_1/P(1-f) + g$$

that is, the utility's required return adjusted for underpricing. For flotation costs of 5%, dividing the expected dividend yield by 0.95 will produce the adjusted cost of equity capital. For a dividend yield of 6% for example, the magnitude of the adjustment is 32 basis points: .06/.95 = .0632.

In deriving DCF estimates of fair return on equity, it is therefore necessary to apply a conservative after-tax allowance of 5% to the dividend yield component of equity cost.

Even if no further stock issues are contemplated, the flotation adjustment is still permanently required to keep shareholders whole. Flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years, even if no future financing is contemplated. This is demonstrated by the numerical example contained in pages 7-9 of this Appendix. Moreover, even if the stock price, hence the DCF estimate of equity return, fully reflected the lack of permanent allowance, the company always nets less than the market price. Only the net proceeds from an equity issue are used to add to the rate base on which the investor earns. A permanent allowance for flotation costs must be authorized in order to insure that in each year the investor earns the required return on the total amount of capital actually supplied.

The example shown on pages 7-9 shows the flotation cost adjustment process using illustrative, yet realistic, market data. The assumptions used in the computation are shown on page 7. The stock is selling in the market for \$25, investors expect the firm to pay a dividend of \$2.25 that will grow at a rate of 5% thereafter. The traditional DCF cost of equity is thus $k = D/P + g = 2.25/25 + .05 = 14\%$. The firm sells one share stock, incurring a flotation cost of 5%. The traditional DCF cost of equity adjusted for flotation cost is thus $ROE = D/P(1-f) + g = .09/.95 + .05 = 14.47\%$.

The initial book value (rate base) is the net proceeds from the stock issue, which are

$23.75, that is, the market price less the 5% flotation costs. The example demonstrates that only if the company is allowed to earn 14.47% on rate base will investors earn their cost of equity of 14%. On page 8, Column 1 shows the initial common stock account, Column 2 the cumulative retained earnings balance, starting at zero, and steadily increasing from the retention of earnings. Total equity in Column 3 is the sum of common stock capital and retained earnings. The stock price in Column 4 is obtained from the seminal DCF formula: $D_1/(k - g)$. Earnings per share in Column 6 are simply the allowed return of 14.47% times the total common equity base. Dividends start at $2.25 and grow at 5% thereafter, which they must do if investors are to earn a 14% return. The dividend payout ratio remains constant, as per the assumption of the DCF model. All quantities, stock price, book value, earnings, and dividends grow at a 5% rate, as shown at the bottom of the relevant columns. Only if the company is allowed to earn 14.47% on equity do investors earn 14%. For example, if the company is allowed only 14%, the stock price drops from $26.25 to $26.13 in the second year, inflicting a loss on shareholders. This is shown on page 9. The growth rate drops from 5% to 4.53%. Thus, investors only earn 9% + 4.53% = 13.53% on their investment. It is noteworthy that the adjustment is always required each and every year, whether or not new stock issues are sold in the future, and that the allowed return on equity must be earned on total equity, including retained earnings, for investors to earn the cost of equity.

ASSUMPTIONS:

ISSUE PRICE =	\$25.00
FLOTATION COST =	5.00%
DIVIDEND YIELD =	9.00%
GROWTH =	5.00%
EQUITY RETURN =	**14.00%**
(D/P + g)	
ALLOWED RETURN ON EQUITY =	**14.47%**
(D/P(1-f) + g)	

Yr	COMMON STOCK (1)	RETAINED EARNINGS (2)	TOTAL EQUITY (3)	STOCK PRICE (4)	MARKET / BOOK RATIO (5)	EPS (6)	DPS (7)	PAYOUT (8)
--------	--------	--------	--------	--------	--------	--------	--------	--------
1	$23.75	$0.000	$23.750	$25.000	1.0526	$3.438	$2.250	65.45%
2	$23.75	$1.188	$24.938	$26.250	1.0526	$3.609	$2.363	65.45%
3	$23.75	$2.434	$26.184	$27.563	1.0526	$3.790	$2.481	65.45%
4	$23.75	$3.744	$27.494	$28.941	1.0526	$3.979	$2.605	65.45%
5	$23.75	$5.118	$28.868	$30.388	1.0526	$4.178	$2.735	65.45%
6	$23.75	$6.562	$30.312	$31.907	1.0526	$4.387	$2.872	65.45%
7	$23.75	$8.077	$31.827	$33.502	1.0526	$4.607	$3.015	65.45%
8	$23.75	$9.669	$33.419	$35.178	1.0526	$4.837	$3.166	65.45%
9	$23.75	$11.340	$35.090	$36.936	1.0526	$5.079	$3.324	65.45%
10	$23.75	$13.094	$36.844	$38.783	1.0526	$5.333	$3.490	65.45%
			5.00%	5.00%		5.00%	5.00%	

Yr	COMMON STOCK (1)	RETAINED EARNINGS (2)	TOTAL EQUITY (3)	STOCK PRICE (4)	MARKET / BOOK RATIO (5)	EPS (6)	DPS (7)	PAYOUT (8)
------	--------	--------	--------	--------	--------	--------	--------	--------
1	$23.75	$0.000	$23.750	$25.000	1.0526	$3.325	$2.250	67.67%
2	$23.75	$1.075	$24.825	$26.132	1.0526	$3.476	$2.352	67.67%
3	$23.75	$2.199	$25.949	$27.314	1.0526	$3.633	$2.458	67.67%
4	$23.75	$3.373	$27.123	$28.551	1.0526	$3.797	$2.570	67.67%
5	$23.75	$4.601	$28.351	$29.843	1.0526	$3.969	$2.686	67.67%
6	$23.75	$5.884	$29.634	$31.194	1.0526	$4.149	$2.807	67.67%
7	$23.75	$7.225	$30.975	$32.606	1.0526	$4.337	$2.935	67.67%
8	$23.75	$8.627	$32.377	$34.082	1.0526	$4.533	$3.067	67.67%
9	$23.75	$10.093	$33.843	$35.624	1.0526	$4.738	$3.206	67.67%
10	$23.75	$11.625	$35.375	$37.237	1.0526	$4.952	$3.351	67.67%
			4.53%	4.53%		4.53%	4.53%	